Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina
Application of Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina

Post-Hearing Exhibit 1a

1989 Va. PUC LEXIS 180

Virginia State Corporation Commission

December 28, 1989

CASE NO. PUE890051

Reporter
1989 Va. PUC LEXIS 180 *

APPLICATION OF OLD DOMINION ELECTRIC COOPERATIVE and VIRGINIA ELECTRIC AND POWER COMPANY, For approval of new generation facilities pursuant to Virginia Code § 56-234.3 and for a certificate of public convenience and necessity pursuant to Virginia Code § 56-265.2

Core Terms

clover, electric, public convenience, consortium, solicit, burn, coal-fired, finance, certificate, co-applicants, unsolicited, baseload, estimate, staff, bid

Opinion

[*1]

FINAL ORDER

On June 12, 1989, Old Dominion Electric Cooperative ("ODEC" or "the Company") filed an application, accompanied by prepared testimony and exhibits, requesting the Commission to approve the Company's proposed construction of a new generating facility under *Va. Code § 56-234.3* and to grant a certificate of public convenience and necessity for that facility under *Va. Code § 56-265.2*. In its application as originally filed, ODEC proposed to construct a 393 MW pulverized coal-fired generating facility at a site near Clover, Virginia.

On July 6, 1989, the Commission issued its Order for Notice and Hearing by which it established a procedural schedule for ODEC, protestants, the Commission's Staff, and intervenors and set a public hearing.

On August 15, 1989, ODEC and Virginia Electric and Power Company ("Virginia Power") filed a joint motion requesting that the application filed by ODEC be amended to include Virginia Power as a co-applicant and to include a second 393 MW coal-fired unit. As stated in the joint motion, amended application, and supporting materials, Virginia Power and ODEC **[*2]** had agreed in principle to the construction and joint ownership of both Clover units. Each participant would own a 50% undivided interest in the generating facility. The rates for sales of power from the 50% interest owned by ODEC would not be regulated by this Commission since the Company is a wholesale power cooperative under Va. Code § 56-231.1 et seq., whereas the 50% interest owned by Virginia Power would be fully regulated by this Commission in the same manner as all other Virginia Power generating plants. Virginia Power agreed to be the operating agent for the project and to act as ODEC's agent for procurement of fuel for the units. Both Virginia Power and ODEC have noted that they expect to realize a net reduction in the cost of the units from $ 1,137 per kW to $ 1,024 per kW by constructing two units instead of one.

By order dated August 23, 1989, the Commission granted the joint motion and extended the time in which protestants had to file their notices of protest, protests, and testimony.

The Commission convened a hearing on this matter on October 30, 1989. Counsel appearing included: Nathan Miller, Esquire, Micheal L. Hern, Esquire, and William S. Bilenky, Esquire, **[*3]** for ODEC; John E. Cunningham, Esquire, and Darla B. Tarletz, Esquire, for Virginia Power; Edward L. Flippen, Esquire, George B. Wickham, Esquire, and Charles H. Tenser, III, Esquire, for Ultrasystems Development Corporation and UtilCo Group Inc. ("Ultrasystems" and "UtilCo"); Stephen H. Watts, II, Esquire, for Black & Veatch Engineers and Architects, Westinghouse Electric Corporation, Combustion Engineering, Inc., and H. B. Zachary Company (hereafter collectively referred to as "the Consortium"); James C. Dimitri, Esquire, for the Committee for Fair Utility Rates ("Virginia Committee"); M. Brooks Savage, Jr., Esquire, for the Virginia Pipe Trades Council ("VPTC"); and Deborah V. Ellenberg, Esquire, and Sherry H. Bridewell, Esquire, for the Commission's Staff.

Eight public witnesses also appeared. Many of these witnesses urged the Commission to approve the construction of these units and to authorize the issuance of a certificate of public convenience and necessity for them. Two of the public witnesses expressed concern about the potential environmental effects of the proposed units.

During the hearing, the co-applicants, Commission Staff, Ultrasystems and UtilCo, and VPTC presented **[*4]** testimony. The Virginia Committee and the Consortium participated in the hearing, but did not present testimony. Counsel for Ultrasystems and UtilCo asked that we make no ruling in this case prejudicial to Ultrasystems and UtilCo's pending petition, docketed as Case No. PUE890041. In response to that position, we stated that the instant proceeding would not be considered <u>stare decisis</u> on the proper calculation of the avoided cost rate for Ultrasystems and UtilCo, an issue before us in Case No. PUE890041.

On November 7, 1989, Virginia Power, ODEC, VPTC, the Consortium, Staff, the Virginia Committee, and Ultrasystems and UtilCo filed post-hearing memoranda and briefs. Only VPTC urged the Commission to deny the joint application, on the grounds that the co-applicants did not demonstrate that the proposed Clover generating station was the most economical and reliable alternative for meeting their respective energy needs.

<u>The Applicable Legal Standard</u>

Under *Virginia Code §§ 56-234.3* and -265.2, the Commission must determine that the construction of the Clover units is "necessary to enable the public utility to furnish reasonably adequate **[*5]** service and facilities at reasonable and just rates," and that the "public convenience and necessity" require their construction. In cases of this nature, the utility must bear the burden of proof. We previously have identified several factors which must be demonstrated to satisfy this burden:

> Among these factors are that the utility will have a need for additional power within the time frame contemplated; that its cost estimates, choice of technology, construction plans and proposed manner of carrying out the project are reasonable, and that there are no suitable alternatives to the proposed construction, such as conservation and load management, upgrading existing units, or obtaining the necessary power from resources other than the utility's own facilities.

<u>Application of Virginia Electric and Power Company</u>, Case No. PUE860058, 1987 S.C.C. Ann. Rep. 262. (Footnotes omitted). Measured by this standard, it is evident that Virginia Power and ODEC have met their respective burdens of proof and have demonstrated that the Clover units are in the public interest.

<u>Need for the Proposed Units</u>

ODEC and Virginia Power have demonstrated that they need the baseload capacity **[*6]** the Clover units will provide by the years 1994-1995. ODEC has demonstrated that it needs baseload capacity to replace power now supplied by Allegheny Power System ("APS"). Currently, 300 MW of capacity is being provided to ODEC by APS under a contract scheduled to terminate in 1993. Under the contract, the term of the agreement could be extended for two one-year periods in the event that power is available. ODEC's application and supporting testimony indicated that, based on the planning records of APS and discussions between ODEC and the management of

APS, power would be available for purchase by ODEC through 1993, but would be less likely to be available for the second one-year extension period. Thus, ODEC asserted that the Clover unit was necessary to replace power now being purchased from APS.

Further, power supplied to ODEC from the APS purchase now functions as baseload capacity for ODEC. Staff testified that any replacement power source for the APS purchase should have baseload unit characteristics, i.e., low operating costs and more efficient operation over long periods of time.

Virginia Power identified three reasons why it needs the additional power available from the **[*7]** Clover units: (1) the loss of a baseload cogeneration facility modeled at 240 MW; (2) the completion of a study indicating that Virginia Power's targeted reserve margin should be increased from 18.5% to 21%; and (3) the economical power supply option represented by the Clover units.

To support its part of the application for the Clover units, Virginia Power employed a generation expansion planning model to determine its least cost generation expansion plan. That study weighed the benefits of more capital-intensive additions with lower energy costs against less capital-intensive additions with higher energy costs to determine the most economical generation mix to meet Virginia Power's system capacity needs. It demonstrated that Virginia Power needs the capacity and that the Clover units are the optimal choices of the candidate technologies and unit sizes considered.

Cost Estimates, Choice of Technology, and Construction Plans

In 1986, as ODEC considered how to replace the APS power it knew would be discontinued, it received several solicited proposals. ODEC hired the engineering and architecture firm of Burns and McDonnell to assist it in the evaluation of its energy alternatives. **[*8]** This evaluation included both technical and economic comparisons of the proposals. ODEC's evaluation eliminated all but two of these proposals. ODEC, together with Burns & McDonnell, concluded that a pulverized coal-fired unit represented the least cost and least risky fuel option. Because the proposals ODEC had received for a coal unit exceeded the estimate of construction prepared prior to bidding, the project was rebid. When the project was rebid, ODEC received three responses and twelve unsolicited responses from nonutility generators. Burns and McDonnell evaluated the solicited and unsolicited bids, using price and nonprice factors to quantify the reliability of the unsolicited proposals. The best solicited alternative was compared to the best unsolicited proposal, and the Clover units emerged as the winning bid.

Burns & McDonnell reviewed the cost and technical aspects of the proposed contract during negotiations with the Consortium. Burns & McDonnell will also monitor the Consortium's performance under the contract and its plans for design, procurement, and construction to ascertain that reasonable times and sequences are included in the Consortium's schedules.

Under the terms **[*9]** of the contract executed with the Consortium on April 6, 1989, the Consortium proposed to construct a 393 MW net electric plant utilizing a pulverized coal-fired boiler and a wet limestone sulfur dioxide absorption system with baghouse for flue gas treatment. The proposed project consisted initially of one unit with common facilities for a second unit of similar size. The plant was to be sited near Clover, Virginia, and would utilize makeup water from the Staunton River and a mechanical draft cooling tower on a closed loop cooling system for heat rejection. Site preparation is expected to proceed in parallel with environmental permitting so that the first unit would be on line and in commercial operation by December, 1993. The contract price for a single unit was approximately $ 447 million.

On August 15, 1989, Virginia Power signed an agreement in principle with ODEC to participate in the construction of the two-unit facility. While Burns & McDonnell would monitor implementation of the Consortium contract, a construction management committee, composed of ODEC and Virginia Power representatives, would have oversight to insure compliance with the contract and to direct appropriate **[*10]** changes when necessary. Virginia Power expects to operate the units over their projected life and to provide fuel procurement services for the facility. According to ODEC, the second unit would be commercialized by December, 1994. The cost for the two units is estimated to be $ 805 million, or $ 1024 per kW.

Virginia Power has testified that it also will be responsible for the design and construction of the transmission facilities necessary to interconnect the station with the rest of its system. The co-applicants have testified that transmission facilities for the Clover units would cost approximately $ 75 million and would necessitate the initial installation of two 230 kV transmission lines with a 500 kV line later to be installed to assure reliable transmission from the facility.

The joint application is not without its uncertainties. ODEC's financing for the joint project has not been specifically identified. Although ODEC is optimistic about receiving a loan guarantee for the project from the Rural Electrification Administration ("REA"), that guarantee is not yet certain and is pending completion of environmental impact assessments. The record, however, demonstrates that the **[*11]** project is financially feasible, and that there is a great deal of interest among lenders in providing capital for the project. It appears that Virginia Power's participation in the project has raised the "comfort level" of potential lenders.

ODEC, with the assistance of its financial advisor, Merrill Lynch, sent requests for proposals to a select group of 19 banks to secure construction financing with an option to convert to permanent financing if the REA loan guarantee is not approved. ODEC selected these banks because of their expertise in utility or electric cooperative financing, project financing expertise, previous experience with the construction Consortium, ability to lead and manage an entire project, and their strong syndication capabilities. Given these ongoing developments, the fact that lenders have not been selected for the Clover project is not fatal to this application.

With respect to Virginia Power, its ability to raise capital for its share of the project is not in question. Virginia Power's financing arrangements will be subject to rate case scrutiny and applications for security issuances under Chapter 3 of Title 56 of the Virginia Code. In that sense, Virginia **[*12]** Power's financing for this project is no different than that for any of its solely-owned plants.

An additional issue which was raised during the proceeding related to the effect of acid rain legislation on the viability of the Clover units. The effect of such legislation is unknown and unquantifiable at this time. The co-applicants have considered the possible effects of acid rain legislation as part of their respective analyses. ODEC, for example, used the cost of 1.15% low sulfur coal in its evaluation of the Clover and other generation alternatives. In our opinion, the probability of the enactment of acid rain legislation in some form does not justify the denial of this application.

We find that ODEC and Virginia Power have borne their burden of proof and have shown that their cost estimates, choice of technology, construction plans, joint ownership, and proposed manner of carrying out the project are reasonable.

<u>Alternatives to the Proposed Construction</u>

No party to this proceeding has identified a readily available alternative to the construction of the Clover units. Only one party, VPTC, opposes their construction. VPTC criticized ODEC for not soliciting NUG responses as **[*13]** part of its request for proposals. VPTC proposes that we continue this proceeding until next spring at which time we may receive a report on Virginia Power's 1989 solicitation to determine whether, after comparing Clover with those units, it is still the least-cost generation option.

In response to the foregoing, we note that we have never adopted a policy which requires the use of competitive bidding procedures. Instead, we recognize that the parameters we have previously suggested for a competitive solicitation:

> . . . are binding on no party; thus utilities are free to adopt or reject a competitive negotiation procedure. If adopted, the choice of the actual details of the program is one which the utility must make initially. Since each utility has unique operational characteristics, we would presume that such programs might also differ among utilities.

Commonwealth of Virginia, At the relation of the State Corporation Commission, Ex Parte: In the matter of adopting Commission policy regarding the purchase of electricity by public utilities from qualifying facilities when there is a surplus of power available, Case No. PUE870080, 1988 S.C.C. Ann. Rep. 297 at 299. (Footnotes **[*14]** omitted.)

On the other hand, the record indicates that ODEC did consider various sources of generation prior to filing its application. As noted above, ODEC issued an initial RFP in the fall of 1986 to potential suppliers of constructed generation resources. The Company received four proposals in the spring of 1987, and retained Burns & McDonnell to evaluate the proposals. ODEC and Burns & McDonnell hoped to improve the prices received for the utility's generation needs and, accordingly, rebid the project. Concurrently, ODEC also received a number of unsolicited cogeneration, independent power producer, and lease proposals. An economic analysis performed on each of these proposals, together with the two remaining solicited bids, resulted in ODEC's choice of the Clover units as the preferred alternative.

Parenthetically, we recognize that ODEC's process by which it considered alternatives to a unit it would own and build was not without flaws. However, we find that the process did eventually compare possible alternatives with the preferred construction proposal.

Similarly, Virginia Power has compared the Clover facility with the coal-fired capacity offered through the competitive **[*15]** market in its March, 1988, solicitation and with its own company-owned and constructed alternatives. Virginia Power has determined that the costs of these units were reasonable when compared with those offered by the market and with the alternative projects it could construct and own. No affirmative evidence has been offered to show that there are existing generation alternatives which are better than the Clover project.

Indeed, the only NUG participant in this proceeding does not oppose the issuance of a certificate of public convenience and necessity for the Clover units. Even after extensive public notice of this project for environmental scoping meetings and to advertise the instant application, no NUG has come forward to oppose the project. We will not deny this joint application on the outside chance that there may be some as yet unidentified NUG with an interest at odds with this project.

In sum, we find that:

(1) ODEC's and Virginia Power's joint proposal for the construction of the two 393 MW net, coal-fired generating units near Clover, Virginia, are improvements to each utility's system which are necessary to enable these utilities to furnish reasonably adequate service **[*16]** and to meet each utility's expected capacity shortfalls. The Clover generating station should, therefore, be approved pursuant to *Va. Code § 56-234.3*;

(2) ODEC's and Virginia Power's joint construction of such facilities for use in public utility service is also required by the public convenience and necessity, pursuant to the provisions of *Va. Code § 56-265.2*; and

(3) Upon the filing of the appropriate maps by the applicants, a certificate of public convenience and necessity should be issued.

Accordingly, IT IS ORDERED:

(1) That ODEC's and Virginia Power's proposed joint construction of two 393 MW net pulverized coal-fired units, to be located near Clover, Virginia, is hereby approved pursuant to *Va. Code § 56-234.3*, subject to ongoing Commission supervision as allowed by law;

(2) That a certificate of public convenience and necessity for the Clover generating units shall be issued pursuant to *Va. Code § 56-265.2*, upon the filing of the appropriate maps by the applicants; and

(3) That this matter shall be continued until **[*17]** such time as the appropriate maps are received, whereupon it will be dismissed by further Commission order.

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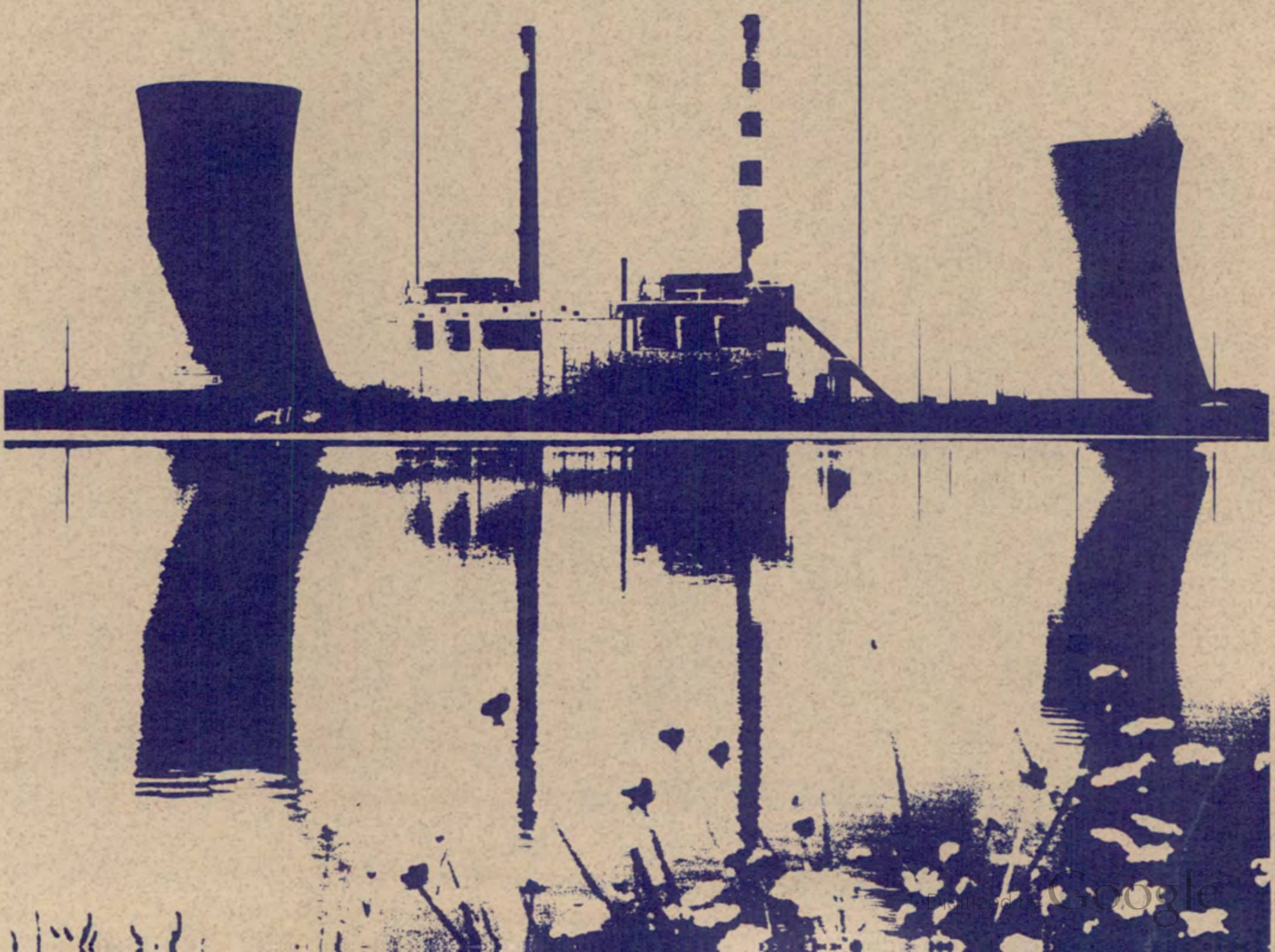
Fuel Choice in Steam Electric Generation: Historical Overview

Energy Information Administration
Washington, D C

Published:
August 1985



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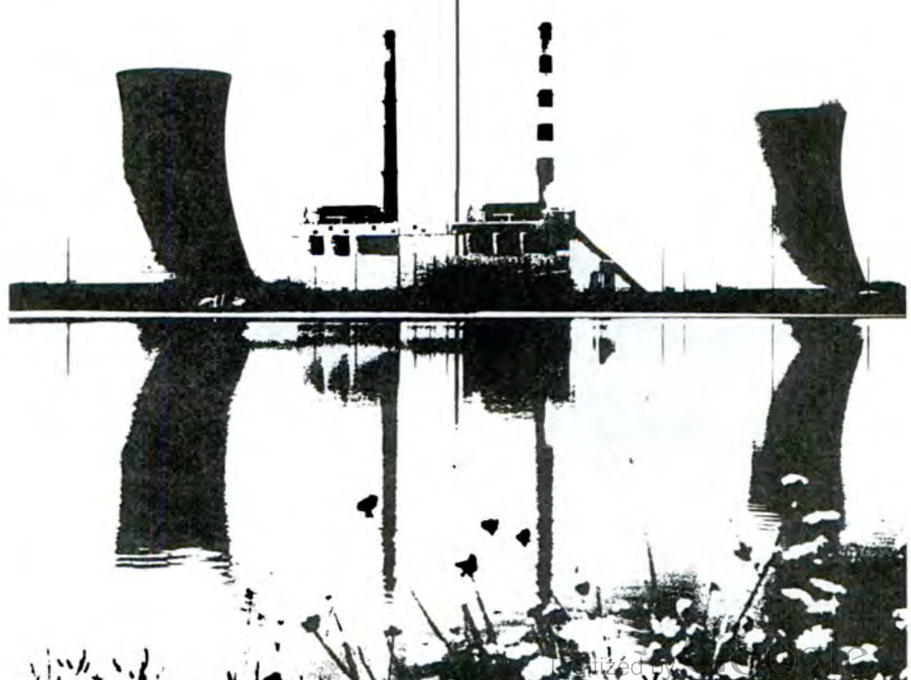

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Preface

This report presents data on fuel use by electric utilities in the short term. Short-term options for fuel choice include the selection of fuel for multifuel boilers, the mix of different generators that utilities use at a given time, and the purchase of power. Long-term decisions, such as the construction of new capacity, are not covered in this report. Since about three-fourths of the Nation's electricity is generated from fossil fuels and some fossil-fueled boilers have the capacity to switch fuels, the report focuses primarily on fossil-fuel choice.

Fuel use on a monthly basis is reviewed for each of 12 regions. The regions are based on the regional reliability councils (and certain subcouncils that have special fuel-use characteristics) of the North American Electric Reliability Council (NERC) within the contiguous United States. The influence of fossil-fuel costs, environmental and fuel-use legislation, and supply disruptions on fuel use is discussed. The report also describes constraints on short-term fuel choice associated with the operation of boilers capable of burning more than one fossil fuel and transmission constraints.

A companion report, "Fuel Choice in Steam Electric Generation: Statistical Analysis," presents a statistical analysis of fuel choice and examines the issues affecting fuel choice in a more rigorous fashion.

These reports are intended for public utility analysts, policy analysts working in the electric utilities area, investment analysts, trade associations, equipment manufacturers, legislators, and regulatory authorities.

This report has been prepared under the authority of Section 54 of the Federal Energy Administration Act of 1974 (P.L. 93-275), which requires establishment of an analytic capability and analysis of energy information.

Contents

Contents

Contents

Tables

Contents

Figures

Contents

Figures

Executive Summary

The choice of fuels used to generate electricity is of major importance both to the electric utilities and to their customers. Fossil-fuel costs are important components of electricity costs; severe increases in fossil-fuel costs have caused sharply higher electricity prices for consumers during the 1970's and 1980's. Electric utilities may respond to increasing fuel costs by switching to fuels that produce the lowest cost electricity. Electric utilities can do this in the short term in three ways: (1) by switching to the least expensive fuel in a multifuel boiler, (2) by choosing the mix of different generators used at a given time to minimize fuel cost as well as overall generation cost, and (3) by purchasing power. Utilities also consider fuel costs in deciding on the type of fuel to be used in a new plant. Factors that influence fuel choice and restrict the ability of utilities to respond to changes in relative fuel costs include the amounts of generating capacity by fuel type, fuel availability, technical factors (boiler design characteristics and transmission constraints), fuel supply disruptions (including strikes, embargoes, and curtailments), environmental restrictions that may affect the use of specific fuels (especially coal), and regulations that may affect fuel choice (such as the Powerplant and Industrial Fuel Use Act).

This report presents data on utility fuel use for generation for the short term, which includes both the choice of fuel for multifuel boilers and the mix of different generators in use at a given time. Fuel choice for the short term may also include the purchase of power. Fuel use on a monthly basis is reviewed for each of 12 regions (Figure ES1). The regions are based on the regional reliability councils (and certain subcouncils) of the North American Electric Reliability Council (NERC).[1] The subregions used in this study allow concentration on specific areas that have special fuel-use characteristics.

Fossil-fuel steam generation produced 73 percent of the electricity generated in the contiguous United States in 1984, nuclear generation 14 percent, and hydroelectric generation virtually all the rest (Table ES1). Figures ES2 and ES3 show annual net generation and percent of total generation by energy source, respectively, for the United States during the period from 1970 through 1984. In Figure ES2, the scale of the vertical axis differs on each graph, which should be noted when comparing the amounts of generation for each fuel. Because of the large share of electricity generation from fossil fuels and the capability of some boilers to switch from one fossil fuel to another, this report focuses on fossil-fuel choice.

Fuel Use

Coal-fired generation increased from 46 percent of total net generation in the United States in 1970 to 56 percent in 1984, and nuclear-powered generation

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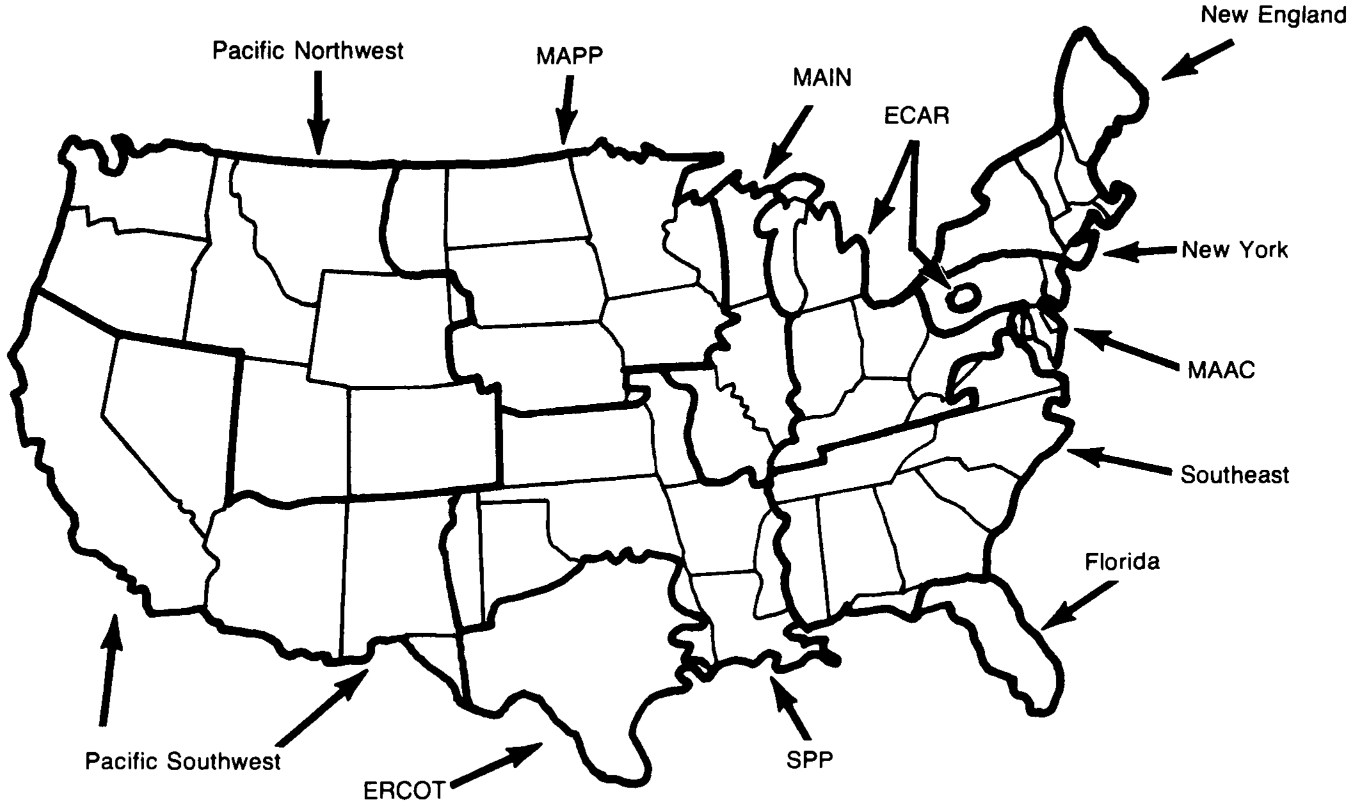
[1]The North American Electric Reliability Council (NERC) was formed by the electric utility industry in 1968 to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America.

Executive Summary

Figure ES1. Regions Used for Fuel Choice Overview



New England: The New England Power Pool subregion of the Northeast Power Coordinating Council (NPCC).

Southeast: The Southeastern Electric Reliability Council (SERC), excluding the Florida subregion.

ECAR: East Central Area Reliability Coordination Agreement.

MAIN: Mid-America Interpool Network.

SPP: Southwest Power Pool.

ERCOT: Electric Reliability Council of Texas.

New York: The New York Power Pool subregion of NPCC.

MAAC: Mid-Atlantic Area Council.

Florida: The Florida subregion of SERC. Note that the part of western Florida served by Gulf Power is assigned to the Southeast region.

MAPP: Mid-Continent Area Power Pool (United States only), formerly the Mid-Continent Area Reliability Coordination Agreement (MARCA).

Pacific Southwest: Arizona-New Mexico Power Area and California-Southern Nevada Power Area of WSCC. Note that the part of Texas served by El Paso Electric is part of the Pacific Southwest region.

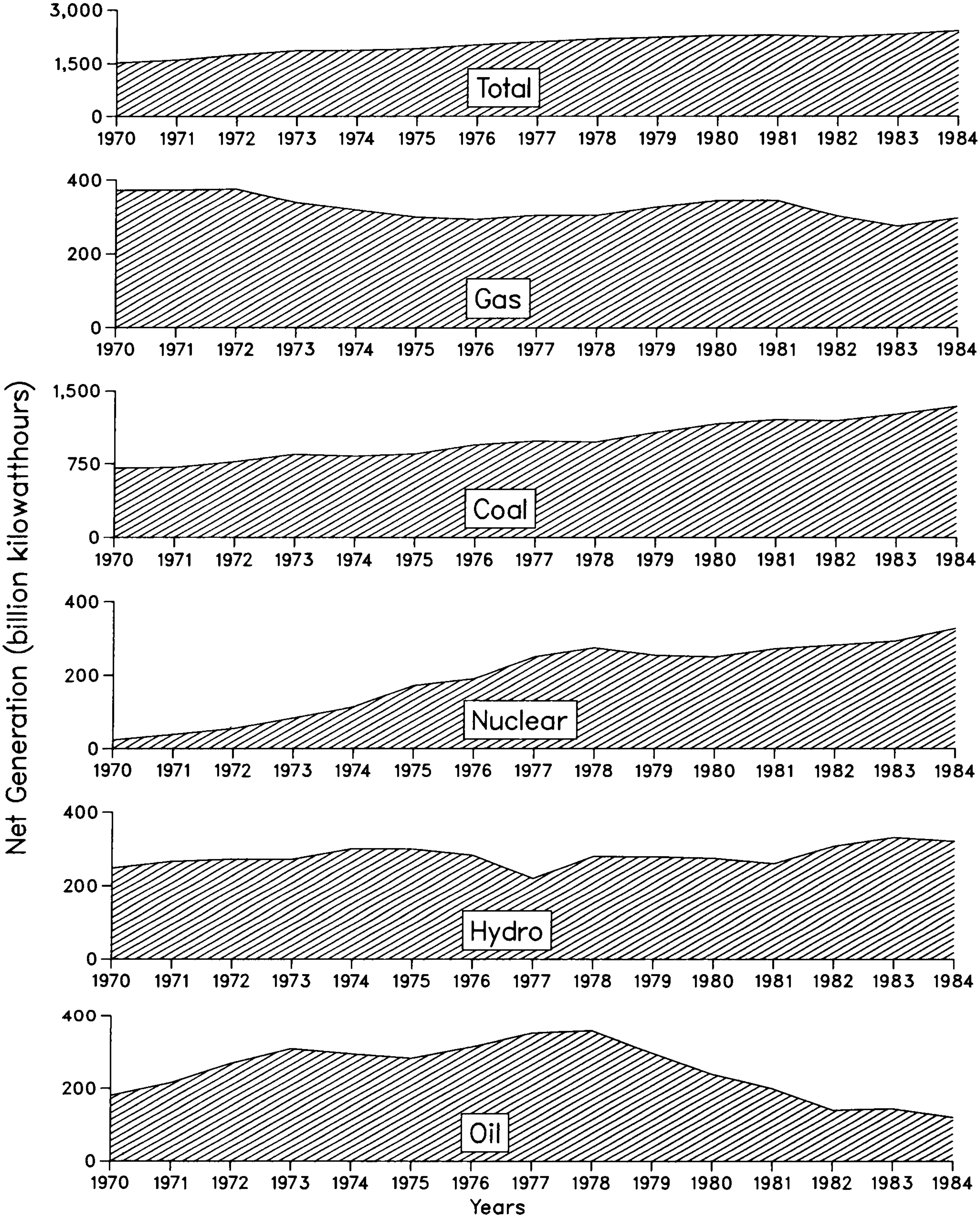
Pacific Northwest: Northwest Power Pool Area and Rocky Mountain Power Area of the Western Systems Coordinating Council (WSCC). Note that Northern Nevada is part of the Northwest Power Pool Area, but has no power plants; thus the State is treated as part of the Pacific Southwest for this study.

Note: Regions are based on the regional reliability councils (and certain subcouncils) of the North American Electric Reliability Council (NERC).

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, Electric Power Division.

Executive Summary

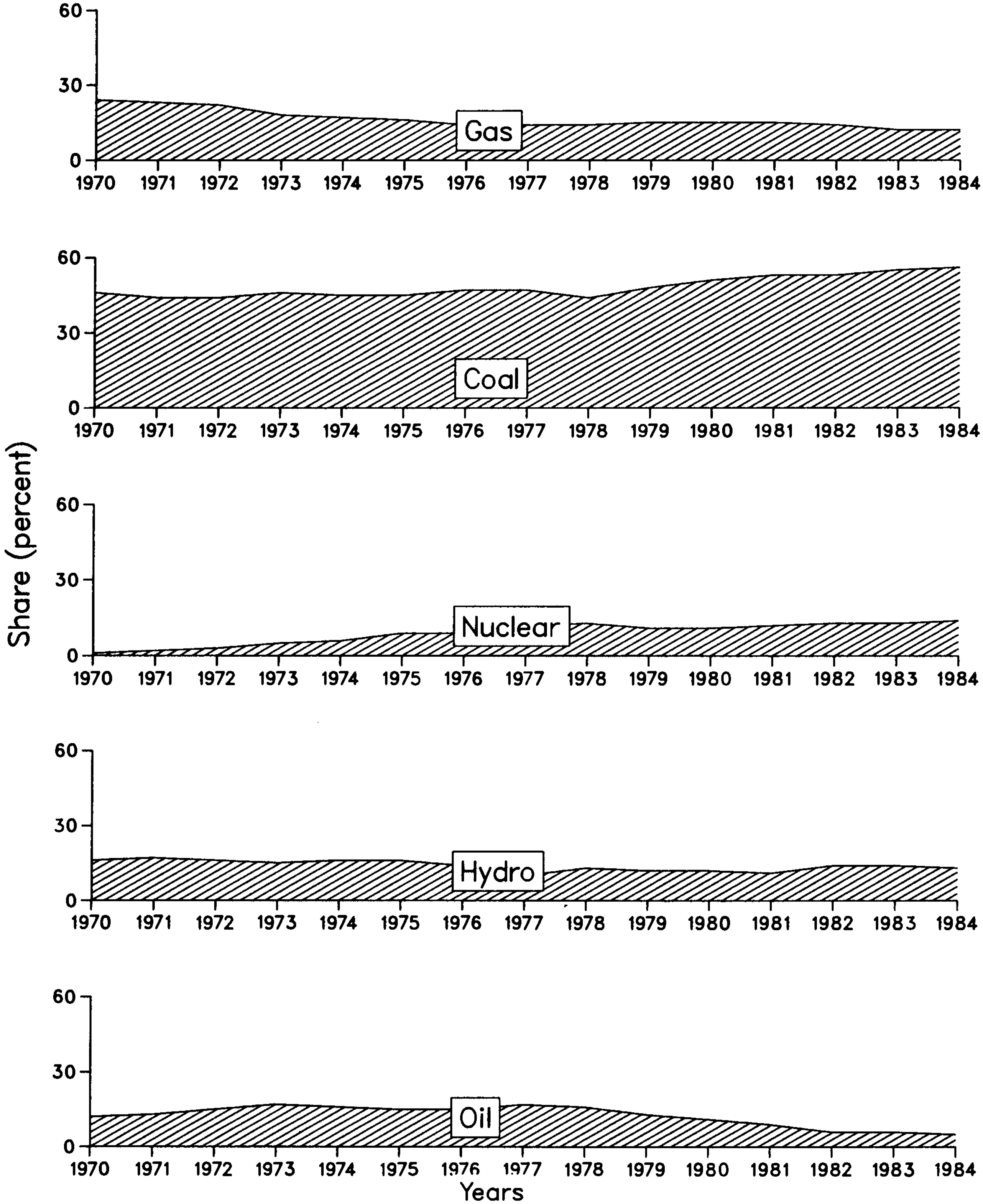
Figure ES2. Net Generation by Energy Source, 1970-1984



Note: Scale for vertical axis differs for each energy source.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Executive Summary

Figure ES3. Share of Total Net Generation by Energy Source, 1970-1984



Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Executive Summary

Table ES1. Share of Net Generation in the United States by Energy Source, 1970-1984 (Percent)

Year	Coal	Oil	Gas	Nuclear	Hydro-electric
1970	46	12	24	1	16
1971	44	13	23	2	17
1972	44	15	22	3	16
1973	46	17	18	5	15
1974	45	16	17	6	16
1975	45	15	16	9	16
1976	47	15	14	9	14
1977	47	17	14	12	10
1978	44	16	14	13	13
1979	48	13	15	11	12
1980	51	11	15	11	12
1981	53	9	15	12	11
1982	53	6	14	13	14
1983	55	6	12	13	14
1984	56	5	12	14	13

Note: Data for 1970 and 1971 include Alaska and Hawaii while data for other years do not.

Note: Totals may not equal sum of components due to independent rounding.

Sources: •1970-1971: Energy Information Administration, Annual Energy Review 1983 (April 1984), p. 193. o1972-1984: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms. Percentage calculations were performed by Energy Information Administration, Electric Power Division.

increased from 1 percent in 1970 to 14 percent in 1984.[2] Nuclear-powered generation in 1984 hit a record at 328 billion kilowatthours, becoming the second largest generating source of electricity. Oil-fired generation was 12 percent of total generation in 1970 and increased to 17 percent in 1973, probably because of environmental legislation for cleaner air that encouraged a shift from coal-fired to oil-fired generation. Oil-fired generation decreased to 15 percent after the 1973-1974 oil cost increase. It again declined sharply following the 1979-1980 oil cost increase, to 5 percent by 1984.

[2]Net generation is gross generation less the energy consumed at the generating station for station use. Energy required for pumping at pumped-storage plants is regarded as plant use and must be deducted from the gross generation.

Executive Summary

Gas-fired generation was approximately 23 percent of total net generation from 1970 to 1972 and decreased to a low of 14 percent in 1976, caused in part by higher gas prices, fuel-use legislation, and gas shortages; then because of reduced legislative requirements and no gas shortages, gas use increased slightly to 15 percent in 1979. Hydroelectric generation remained relatively constant throughout the period except for a dip in 1977 (a year of severe drought) and an increase in 1982 and then again in 1983 (years of high precipitation).

Fossil-Fuel Costs

Fossil-fuel costs began to increase in the 1970's (Figure ES4). Oil costs increased dramatically, from $0.40 per million Btu in 1970 to $2.03 per million Btu in 1975 (Table ES2). By 1984, the cost of oil was $4.84 per million Btu, nearly three times the cost of coal. Oil costs were probably one of the principal reasons for the reduction in oil-fired generation over the period. Coal and natural gas costs increased as well, but at much lower rates. By 1976, the cost of natural gas exceeded the cost of coal and by 1984 was more than twice the cost of coal.

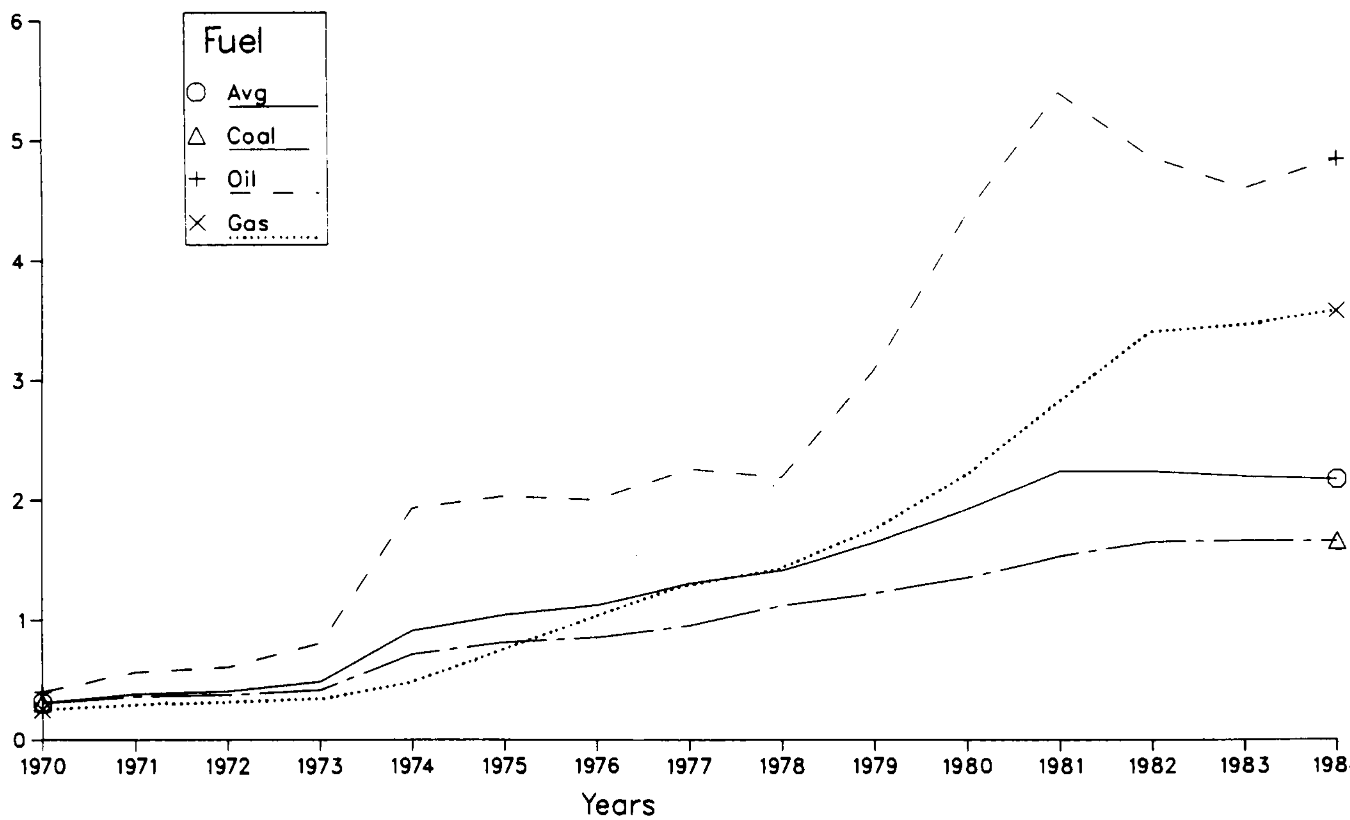
The options for responding to increased oil costs were more limited prior to 1979. Between mid-1972 and the end of 1978, utilities experienced natural gas curtailments and threats of further reductions. Replacing oil with coal or nuclear energy required large-scale construction projects that take many years to complete. Environmental concerns had caused some shift from coal- to oil-fired generation in some regions and limited the extent to which utilities could build new coal-fired plants. By 1979, however, concern over natural gas supply had diminished, and utilities were able to substitute gas for oil in steam generation in many regions. Also, additional coal-fired and nuclear-powered plants ordered earlier began to come on line after 1979.

Federal Environmental and Fuel-Use Regulation

Although most regions that were using substantial oil- or gas-fired capacity prior to the 1979-1980 oil cost increase switched to coal, five regions did not (New England, New York, MAAC, Florida, and Pacific Southwest). Environmental regulations may have restricted switching to coal in these regions, but that is not the only explanation. Coal transportation costs and the capacity limits of transmission systems are also possible explanations for the continued use of oil- and gas-fired generation in these regions. New England, Florida, and California (the largest electricity-producing and -consuming State in the Pacific Southwest region) all lack indigenous coal supplies and are far enough from coal-producing areas to make transportation costs a serious factor. In all of these regions, transmission system limits prevent utilities that depend on oil- or gas-fired generation from importing enough power from coal-fired power plants into their load centers.

Executive Summary

Figure ES4. Fossil-Fuel Costs in the United States, 1970-1984



Note: Average is the quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plant.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuel for Electric Plants," and predecessor forms.

Executive Summary

Table ES2. Fossil-Fuel Costs for Electricity Generation in the United States, 1970-1984 (Dollars per Million Btu)

Year	Coal[a]	Oil[b]	Gas[c]
1970	0.31	0.40	0.27
1971	0.36	0.56	0.29
1972	0.37	0.60	0.31
1973	0.41	0.80	0.34
1974	0.71	1.93	0.48
1975	0.81	2.03	0.75
1976	0.85	2.00	1.03
1977	0.95	2.26	1.29
1978	1.12	2.19	1.43
1979	1.22	3.08	1.75
1980	1.35	4.37	2.21
1981	1.53	5.39	2.82
1982	1.65	4.85	3.40
1983	1.66	4.59	3.47
1984	1.66	4.84	3.58

[a]Data before 1972 include bituminous coal, anthracite, and relatively small amounts of coke, lignite, and wood. Data from 1972 through 1984 include anthracite, bituminous coal, subbituminous coal, and lignite.

[b]Data before 1972 include fuel oil and crude oil, as well as small amounts of tar and gasoline. Data from 1972 through 1984 include fuel oil Nos. 2, 4, 5, and 6 as well as crude oil, topped crude, kerosene, and jet fuel.

[c]Data before 1972 include natural, manufactured, and waste gas. Data from 1972 through 1984 include natural gas, coke oven gas, blast furnace gas, and refinery gas.

Note: Data for 1972-1984 exclude Alaska and Hawaii for consistency with other tables in this report.

Sources: •1970: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1970, Section VII, p. 116; •1971: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry/1983, and predecessor publications; •1972-1984: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

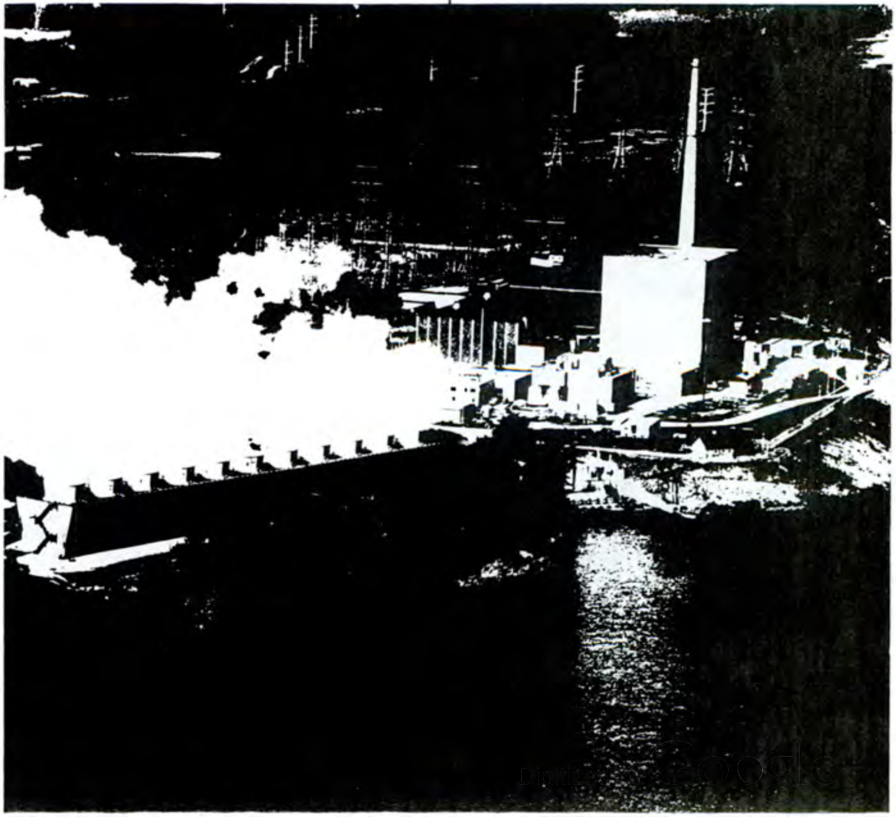
Executive Summary

Implications for the Future

While this report does not forecast future trends in fuel choice, it is worthwhile to consider what the implications may be for the future. The data suggest that changes in fuel costs will play an important role in future fuel-switching decisions. Any major change in relative fuel costs will likely cause the electric utility industry to increase its use of the lower cost fuel. Such changes in use will be constrained in the short run by regulatory factors and by the fuel capabilities of existing generating capacity.

The data also suggest that the utility industry is, by and large, able to respond to shortages of specific fuels by switching to alternate fuels, at least in the short run. The options for fuel switching, however, are primarily available for responding to coal strikes or natural gas shortages. Under current conditions, there may be fewer opportunities to respond to oil shortages (such as another oil embargo). Because of the high cost of oil, most utilities have already switched to other types of generation where physically or legally possible.

Introduction



1. Introduction

Purpose and Scope

The 1973-1974 and 1979-1980 oil price increases led to sharply higher fuel costs and electricity prices for consumers. Because the choice of fuels used to generate electricity is of major importance to both electric utilities and their customers, this report reviews factors that appear to influence utility fuel choice. These factors include fuel costs, capacity availability for each fuel (including engineering constraints on switching fuels in multifuel boilers), fuel supply disruptions (including strikes, embargoes, and curtailments), environmental restrictions affecting the use of specific fuels, and relevant fuel-use regulations.

Electric utilities face two types of fuel-choice decisions. The first, the choice of fuel for new power plants, is a long-term decision. The second type of fuel-choice decision, which is the focus of this report, is the choice of fuel to be used for the short term in actual generation. This second decision includes the choice of fuel for multifuel boilers, the mix of different generators in use at a given time,[1] and the purchase of power.

This report presents information on how utilities responded to (1) increasing fuel costs with existing capacity, (2) fuel supply disruptions, and (3) environmental and fuel-use legislation. Chapter 2 discusses the economics of fuel choice. Chapter 3 discusses environmental and fuel-choice legislation and fuel supply disruptions. Chapter 4 reviews fuel choice in each of 12 regions (Figure ES1), and Chapter 5 summarizes the report.

Fuel Use

A brief review of both short- and long-term fuel-use decisions illustrates the types of factors addressed in this report. In 1984, approximately 86 percent of the electricity produced in the contiguous United States was generated by steam (Table 1).[2] Hydroelectric generation provided virtually all of the rest.[3] Nuclear generation accounted for about 14 percent of total net generation (about

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[1]Because utilities have to maintain enough capacity to meet peak demand, which occurs only a few hours a day and only during certain months, there is usually a choice of different types of capacity available during nonpeak periods. During the nonpeak periods, utilities can use their mix of generators in the most cost-effective manner and this usually means minimizing fuel costs. Chapter 2 discusses the economics of fuel choice in more detail.

[2]Oil- and gas-fired generation data in Table 1 include nonsteam generation, which accounts for less than 1 percent of total generation--a figure too small to affect the discussion.

[3]Combustion turbines, internal combustion (diesel) and "other" (primarily geothermal steam) generation together accounted for about 1 percent of total generation.

Introduction

Table 1. Net Generation of Electricity in the United States, Selected Years (Billion Kilowatthours)

Year	Total[a]	Coal	Share (%)	Oil	Share (%)	Gas	Share (%)	Nuclear	Share (%)	Hydro-electric	Share (%)
1955	547	301	55	37	7	95	17	(b)	(b)	113	21
1960	753	403	54	48	6	158	21	1	(c)	146	19
1965	1,055	571	54	65	6	222	21	4	1	194	18
1970	1,526	704	46	180	12	372	24	22	1	247	16
1971	1,607	713	44	216	13	373	23	38	2	266	17
1972	1,743	771	44	269	15	375	22	54	3	272	16
1973	1,854	847	46	309	17	340	18	83	5	272	15
1974	1,860	828	45	295	16	319	17	114	6	301	16
1975	1,910	852	45	283	15	299	16	173	9	300	16
1976	2,029	944	47	314	15	293	14	191	9	283	14
1977	2,116	985	47	352	17	304	14	251	12	220	10
1978	2,197	975	44	359	16	304	14	276	13	280	13
1979	2,238	1,075	48	297	13	328	15	255	11	279	12
1980	2,277	1,161	51	239	11	344	15	251	11	275	12
1981	2,285	1,203	53	200	9	344	15	273	12	260	11
1982	2,231	1,192	53	140	6	303	14	283	13	309	14
1983	2,300	1,259	55	137	6	272	12	294	13	331	14
1984	2,405	1,342	56	113	5	294	12	328	14	320	13

[a]Total includes "other" (geothermal, wood, wind, waste, and solar) generation.
[b]First nuclear plant was placed in commercial operation in 1957.
[c]Less than 0.5 percent of total.
Note: Data for 1965, 1970, and 1971 include Alaska and Hawaii while data for other years do not.
Note: Totals may not equal the sum of components because of independent rounding.
Sources: •1955-1971: Energy Information Administration, Annual Energy Review 1983 (April 1984), p. 193. •1972-1984: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms. Percentage calculations were performed by Energy Information Administration, Electric Power Division.

16 percent of steam generation).[4] Fossil-fuel steam generation produced 73 percent of all electricity consumed in the contiguous United States in 1984. This report focuses primarily on the fossil fuels used in steam generation for two reasons. First, the largest share of electricity generation is produced by fossil fuels; second, some boilers are capable of switching from one fossil fuel to another fossil fuel as conditions warrant.

[4]Net generation is gross generation less the electric energy consumed at the generating station for station use. Energy required for pumping at pumped-storage plants is regarded as plant use and must be deducted from the gross generation.

Introduction

Although coal was the most important single fuel used to generate electricity, its share of total generation declined from 54 percent in 1965 to 45 percent in 1975. This decline was due, in part, to environmental legislation implemented during this period (Appendix A). Through 1970, oil-fired, gas-fired, and nuclear generation all increased their share relative to coal-fired generation. Between 1970 and 1975, however, gas-fired generation not only fell relative to other fuels, but declined by about 73 billion kilowatthours. Fuel-use legislation (curtailments, in this situation) probably caused these changes in fuel choice. By 1984, coal's share had increased to 56 percent.

Fossil-Fuel Costs

Fossil-fuel costs (including the price of the fuel and its delivery cost) began to increase in the early 1970's and continued to increase throughout the early 1980's (Table 2). The quantity weighted average cost (using the Btu of coal, oil, and natural gas delivered to power plants) of fossil fuel for electricity generation of $0.25 per million Btu in 1965 increased to $1.04 by 1975, and to $2.24 by 1981. Of three fossil fuels (coal, oil, and gas), the cost of oil rose most dramatically. In 1974, following the oil embargo of October 1973 through March 1974, the average cost of oil delivered to steam electric generating plants was $1.13 per million Btu higher than in 1973. The late 1970's and early 1980's brought another major rise in the cost of oil. From 1978 to 1981, oil costs rose by $3.20 per million Btu, but then declined by $0.54 in 1982. Although costs to utilities for coal did not surge dramatically at any particular point during the 1970-1984 period, they did increase from $0.31 per million Btu in 1970 to $1.66 in 1984, an overall increase of $1.35. This increase was due partly to environmental legislation, which required the purchase of more expensive low-sulfur coal. The cost of natural gas to electric utilities increased by $3.31 per million Btu from 1970 to 1984.

Capacity Additions

Licensing and construction require from 6 to 8 years for a coal-fired plant and up to 15 years for a nuclear-powered plant. Some of the factors (other than the cost of the fuel itself) affecting the choice of a fuel for the long term include power plant construction costs, operating efficiency, operating and maintenance costs, and environmental legislation. Although changes in fuel choices in the long term are not the focus of this report, long-term factors are discussed to provide a wider perspective.

Between 1965 and 1975, coal capacity additions more than doubled (Table 3). Compared to previous periods, there were large increases in oil capacity additions between 1971 and 1975 and in natural gas capacity between 1965 and 1975. Nuclear capacity also grew substantially after 1965. The large increase in peaking capacity was due to the desire to improve system reliability after the 1965 Northeast blackout showed that additional cold-start capacity was needed for emergencies. This capacity is only incidental to the issues considered in this report.

Introduction

Table 2. Fossil-Fuel Costs for Electricity Generation in the United States, Selected Years (Dollars per Million Btu)

Year	Weighted Average[a]	Coal[b]	Oil[c]	Gas[d]
1965	0.25	0.24	0.33	0.25
1970	0.31	0.31	0.40	0.27
1971	0.38	0.36	0.56	0.29
1972	0.40	0.37	0.60	0.31
1973	0.48	0.41	0.80	0.34
1974	0.91	0.71	1.93	0.48
1975	1.04	0.81	2.03	0.75
1976	1.12	0.85	2.00	1.03
1977	1.30	0.95	2.26	1.29
1978	1.41	1.12	2.19	1.43
1979	1.64	1.22	3.08	1.75
1980	1.92	1.35	4.37	2.21
1981	2.24	1.53	5.39	2.82
1982	2.24	1.65	4.85	3.40
1983	2.20	1.66	4.59	3.47
1984	2.18	1.66	4.84	3.58

[a]Quantity weighted average cost, using Btu of coal, oil, and natural gas delivered to the power plant.

[b]Data before 1972 include bituminous coal, anthracite, and relatively small amounts of coke, lignite, and wood. Data from 1972 through 1984 include anthracite, bituminous coal, subbituminous coal, and lignite.

[c]Data before 1972 include fuel oil and crude oil, as well as small amounts of tar and gasoline. Data from 1972 through 1984 include fuel oil Nos. 2, 4, 5, and 6 as well as crude oil, topped crude, kerosene, and jet fuel.

[d]Data before 1972 include natural, manufactured, and waste gas. Data from 1972 through 1984 include natural gas, coke oven gas, blast furnace gas, and refinery gas.

Note: Data for 1972-1984 exclude Alaska and Hawaii for consistency with other tables in this report.

Sources: •1965 and 1970: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1970, Section VII, p. 116; •1971: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry/1983, and predecessor publications; •1972-1984: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 3. Nameplate Capacity Additions, by Type, 1951-1984 (Megawatts)

Period	Steam Coal	Steam Oil	Steam Gas	Nuclear	Peaking	Hydro-electric	Total
1951-1955	26,891	8,998	9,516	0	598	6,712	52,715
1956-1960	27,412	11,299	9,988	309	605	7,979	57,592
1961-1965	26,193	12,878	10,500	600	1,950	12,409	64,530
1966-1970	47,904	8,909	19,603	5,723	15,362	11,853	109,354
1971-1975	63,365	20,544	20,747	32,943	29,232	11,211	178,042
1976-1980	60,427	15,344	4,420	17,024	6,980	11,211	115,406
1981-1984	38,638	1,658	35	15,691	2,004	3,546	61,572

Note: Includes Alaska and Hawaii.
Source: Energy Information Administration, Generating Unit Reference File.

Power Plant Fuel Conversions

Utilities also responded to rising fuel costs by converting existing generating capacity to more economical fuels. In addition, fuel conversions were undertaken in response to environmental legislation. Between 1965 and 1972, about 400 coal-fired generating units were converted to oil, largely because of environmental requirements.[5] After the 1973 oil embargo, the trend was toward converting oil-fired generating units to coal.[6] By 1983, 11,370 megawatts (MW) of oil-fired capacity had been converted to coal including 3,000 MW of capacity that did not require major modification (Table 4).

[5] Energy Information Administration, "Petroleum Consumption by Electric Utilities: 10 Years After the Arab Oil Embargo," Electric Power Quarterly, January-March 1984, DOE/EIA-0397 (Washington, DC), pp. 3-11.

[6] Converting coal-fired units to burn oil typically requires 1 or 2 months. Converting oil-fired units to burn coal requires 2 to 4 years.

Table 4. Power Plant Oil-to-Coal Conversions by Region, 1974-May 1983 (Megawatts)

Region[a]	Installed Nameplate Capacity
New England	1,595
New York	0
MAAC	1,699
Southeast	2,911
Florida	965
ECAR	0
MAIN	75
MAPP	904
SPP	2,425
ERCOT	0
Pacific Northwest	796
Pacific Southwest	0
Total[b]	11,370

[a] The 12 regions designated for this report (Chapter 4).
[b] Includes 3,000 megawatts of conversions in the form of fuel switching only, not requiring significant changes in the physical plant.

Source: Electric Light and Power (May 1983), p. 33, based on data from U.S. Department of Energy, Office of Fuels Programs, Fuels Conversion Division.

The Economics of Fuel Choice

2. The Economics of Fuel Choice

This chapter discusses how fuel choice is influenced by the interaction between fuel costs and the operating characteristics of electric systems. In general, electric utilities try to make fuel-choice decisions that minimize costs while maintaining a specified level of reliability. The level of reliability is usually defined in terms of the number of outages in a given time period caused by insufficient generating capacity or by mechanical failure of generating or transmission equipment (other than weather-related). Typically, utilities build capacity and operate their systems with the objective of losing load (being unable to meet the demand for electricity, either because of inadequate capacity or unplanned forced outages) no more than 1 day out of 10 years.

The target reliability level is achieved by building sufficient generating capacity and/or by purchasing firm power from other utilities. In general, electric utilities attempt to maintain a 20-percent reserve margin (owned capacity or purchased firm power) over their expected peak load (the amount of capacity required to meet the highest demand during any given time period). Also, virtually all utilities are parties to reliability agreements that provide for emergency support during critical periods.[1]

Load Diversity and Capacity Mix

Electricity demand varies over daily, weekly, and yearly periods. It is usually divided into base, cycling, and peaking loads, where load refers to the demand on the generating capacity for a specified period. Base load is the minimum continuous demand during the period, while peak load is the maximum demand in the same period. Cycling load is the demand during the transition from base to peak loads. These concepts can be illustrated by considering a single weekday.

Base load includes the demand for electricity during the late night and early morning hours, plus whatever additional generation is required by minimum operating levels of on-line generators. Because of the time required to bring a large coal-fired steam plant into service from a cold start, and because both coal-fired and nuclear generators can be damaged by unnecessarily frequent startups and shutdowns, these baseload generators are frequently kept on line at all times (except for required maintenance).

Peak load occurs, typically, in the afternoon, when commercial and industrial activity are at daily maximum and, in summer, when air-conditioning demand is at maximum. Peak load is supplied first by the baseload generators, since peak demand includes baseload demand. The rest of the peak load is supplied by whatever capacity (or purchased power) is needed to meet demand. Peak load, therefore, determines a utility's minimum capacity requirements.

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[1]For more details, see: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, <u>Interutility Bulk Power Transactions: Description, Economics, and Data</u>, DOE/EIA-0418 (Washington, DC, 1983); and Federal Energy Regulatory Commission, <u>Power Pooling in the United States</u> (Washington, DC, 1981).

The Economics of Fuel Choice

Cycling load typically occurs in the morning and late afternoon/early evening. Cycling load is met by increasing generation from baseload generators that were supplying baseload power with less than their full capacity, and by bringing additional generators on line. In large systems, base load can be spread over a number of large generators operating below their maximum capacity, whose unused capacity is thus available for cycling. One requirement for these "cycling units" is that they can be started and shut down quickly, without damaging them. Note that cycling units also contribute to meeting peak load.

Building and operating costs differ for various types of power plants. Large coal-fired and nuclear power plants have the lowest operating costs (primarily fuel and maintenance), but are very expensive to build. Oil- and gas-fired steam power plants are substantially less costly to build, but have much higher operating costs because of higher fuel costs. Nonsteam fossil-fuel power plants, including combustion turbines and diesel engines, are very costly to operate, but have very low construction costs.[2] Hydroelectric power plants are the cheapest of all to operate, but large hydroelectric plants are expensive to build and the number of suitable sites is limited. Smaller hydroelectric plants, and even some large ones, are subject to limited water supplies during certain periods of the year.[3]

Given both the fluctuations in load and the cost characteristics of different types of power plants, cost minimization requires a mix of power plants. Large coal-fired and nuclear power plants typically supply baseload power, although some regions use oil- or gas-fired power plants for base load and a few regions have baseload hydroelectric generation. Older and/or smaller coal-, oil-, or gas-fired steam plants are used for cycling and seasonal peak loads, while combustion turbines and diesels provide power for daily peak loads.[4] Although these generators are expensive to operate, they can be started and stopped quickly and

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[2]New technologies, such as combined-cycle generators, which combine steam and combustion turbine generators, have substantially improved the efficiency of smaller generators. For the most part, however, the new types of generators were not available in sufficient numbers to affect the discussion in this report.

[3]Pumped-storage plants are hydroelectric power plants that have pumps to refill the reservoirs during off-peak periods, using surplus power from other power plants. The pumped-storage plants are then able to generate power during peak periods, with much less dependence on seasonal patterns of water supplies. However, generation from pumped-storage power plants is reported as generation less energy used for pumping. This usually leads to negative net generation data over monthly periods, which can bias the data on hydroelectric generation for regions in which pumped storage is a major component of hydroelectric capacity.

[4]Peaking generators of these types are also used to provide station power at large power plants during emergencies. One of the problems encountered during the 1965 Northeast blackout was the lack of power to restart baseload power plants. Standby generators are now more generally available for this purpose. See: J.T. Wenders, "Peak Load Pricing in the Electric Utility Industry," Bell Journal of Economics, Vol. 7 (Spring 1976) pp. 232-241; and R. Turvey and D. Anderson, Electricity Economics (Baltimore, Maryland: The Johns Hopkins Press, 1977).

can be used in smaller increments than more cost-efficient generators. Hydroelectric generation fits into these loads according to local conditions, and its use cannot be generally characterized.

Economic Dispatch

This mix of different types of power plants can be operated to minimize operating costs using economic dispatch. Economic dispatch means that generators are brought on line and operated so that the incremental cost of providing an additional unit of power is the same for all generators operating below their maximum capacity (adjusted for transmission losses). All generators operating at maximum capacity are assumed to have a lower incremental cost than the incremental cost for the system as a whole.[5]

In practice, economic dispatch is complicated by reliability considerations, including the requirement to maintain adequate spinning and quick-start reserves (excess capacity in generators currently on line and generators that can be brought on line in 10 minutes or less). Transmission system operations and reliability, however, are one of the most serious complications affecting dispatch (Appendix B).

Utilities try to avoid loading transmission capacity to its design limits because loss of a power line could overload the other power lines, causing a "cascading tripout," blacking out an entire region. The 1965 Northeast blackout was caused by the failure of a circuit breaker in a transmission line in Canada, which then overloaded transmission lines in the New England and New York regions.

Operating procedures and standards developed in response to the 1965 blackout provide guidelines for operating transmission systems in order to limit the effects of power line outages and prevent such cascading power losses. These transmission system constraints can force a utility to operate less efficient power plants, even though capacity is available in more efficient power plants.

In addition to adding another option to the fuel-choice decision, bulk power transactions complicate the operation of the transmission system. Generation is often farther removed physically from consumption. Virtually all electric utilities in the contiguous United States are connected to one of three power grids,[6] and can buy and sell bulk power at the wholesale level. Often a utility can purchase power at a cost lower than that of generating its equivalent. Such transactions are very common, and certain power pools (such as the New England and

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[5]See H.H. Happ, "Optimal Power Dispatch--A Comprehensive Survey," IEFF Transactions on Power Apparatus and Systems, Vol. PAS-96 (3) (May/June 1977), pp. 841-854.

[6]The Eastern, Western, and Texas Interconnected Systems. Utilities in each system are synchronized to the same 60-cycle-per-second alternating current, which allows instantaneous power transfers among system members.

New York power pools) use interutility transactions to approximate economic dispatch for an entire region, rather than for just a single utility.[7]

Reliability standards generally require that the purchasing utility maintain enough quick-start or spinning reserves to replace quickly any purchased power lost because of transmission failure or other mechanical problems. The exception is firm power, under which the seller treats the firm power as a requirements sale and provides the reserves (for which the purchaser pays). The result is often that the buyer has unused oil- or gas-fired generating capacity or may even build new capacity that is used only for backup.[8]

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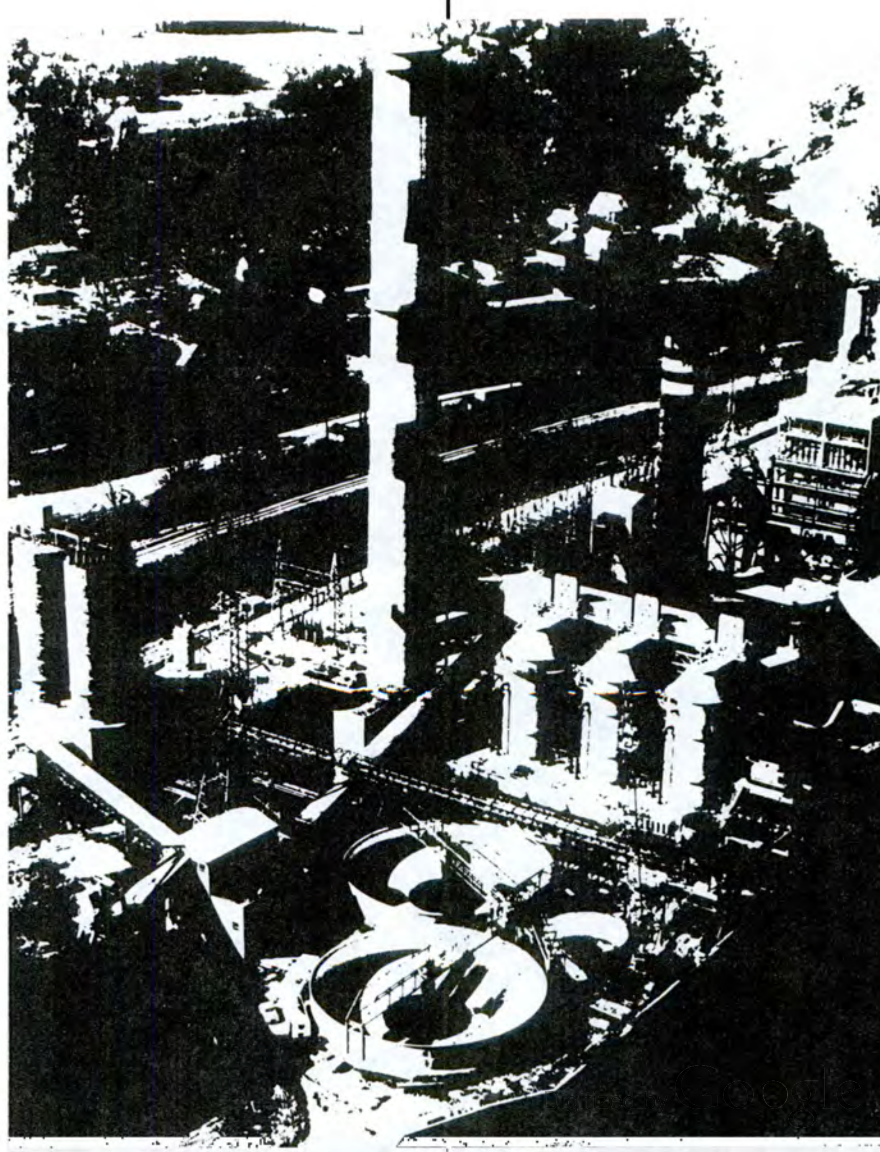
[7]Interutility bulk power transactions are a complex subject because of the variety of institutional arrangements and because of technical factors. See Energy Information Administration, Interutility Bulk Power Transactions: Description, Economics, and Data for a brief and simplified introduction to the subject.

[8]This capacity typically consists of combustion turbines, which are relatively cheap to build and quick-starting but are expensive to operate.

Noncost Influences on Electric Utility Fuel Choice



3. Noncost Influences on Electric Utility Fuel Choice

This chapter discusses some factors other than fuel costs that may have affected electric utilities' fuel choice from 1970 through 1984. These factors include Federal environmental and fuel-use legislation, and supply disruptions.

Federal Environmental and Fuel-Use Legislation

Federal environmental legislation of the 1970's increased the cost of generating electricity by requiring that pollution and emissions control equipment be added to power plants (Appendix A). Equipment required by environmental legislation may comprise about one-quarter of the capital costs of a new coal-fired plant using high-sulfur coal.[1] Operating and maintenance (O&M) costs also rise. Some increased capital and O&M costs are offset by decreased fuel costs, since plants using flue gas desulfurization (FGD) equipment can switch from more expensive low-sulfur coal to less expensive high-sulfur coal. However, coal-fired plants not required to install FGD equipment to meet environmental emission standards may still incur higher costs by being required to switch from high-sulfur to more expensive low-sulfur coal. Environmental legislation also lengthens the planning and construction periods for new power plants. Steps taken to meet environmental requirements may comprise up to 2 of the 8 years required to plan and complete a new coal-fired plant.[2]

During the 1970's, legislation promoted greater use of coal and alternate fuels in order to reduce national dependence on petroleum and natural gas (Appendix A). As of December 31, 1983, 5,700 megawatts of electric generating capacity were prohibited by law from burning petroleum or natural gas and were burning coal as their primary fuel.[3] This capacity represented about 3.5 percent of total oil and natural gas steam generating capacity (including units converted to coal).[4] The energy legislation of the 1970's, which is still in effect, encourages the use of coal by electric utilities while environmental legislation discourages it. Overall, legislation appears to encourage coal use providing that basic environmental requirements are met.

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[1]Derived from information presented in Projected Costs of Electricity from Nuclear and Coal-Fired Power Plants, DOE/EIA-0356/1 (Washington, DC, August 1982), p. 30; and J.A. Reyes Associates, "Regional Capital and Operation and Maintenance Cost Estimates for Emission Control Equipment Required for New Coal-Fired Power Plants," Final Report to Energy Information Administration (Washington, DC, May 1982), pp. 10, 22.

[2]Policy, Planning and Evaluation, Inc., "Impact of Government Regulations on Lead Times of Coal Facilities," Final Report (August 1980), p. C-39.

[3]U.S. Department of Energy, Economic Regulatory Administration, Powerplant and Industrial Fuel Use Act Annual Report (Washington, DC, March 1, 1984), pp. 19-20.

[4]Energy Information Administration, Generating Unit Reference File.

Supply Disruptions

Supply disruptions (such as strikes, curtailments, and the 1973-1974 oil embargo) introduce immediate nonprice influences on fuel choice.

Strikes

Three United Mine Worker (UMW) strikes against coal mines operated by the Bituminous Coal Owners Association occurred between 1973 and 1982: from November 10, 1974 to December 5, 1974 (26 days); the longest coal strike on record, from December 6, 1977 to March 25, 1978 (111 days); and the coal industry's second longest walkout, from March 27, 1981 to June 6, 1981 (72 days). Electric utilities using coal from mines affected by the strikes are located primarily in the central and eastern States of Ohio, Pennsylvania, Indiana, West Virginia, Kentucky, and Michigan, plus Illinois and Missouri, North Carolina, and the portion of Tennessee served by the Tennessee Valley Authority.

No blackouts occurred and, except for voluntary and State-ordered cutbacks, electric service continued uninterrupted, even through the 1977-1978 strike. In anticipation of these strikes, utilities increased their coal stockpiles. Before the 1977 strike, utilities' stocks approached a 100-day supply, a record at the time. In addition, western coal mines, generally not covered by the UMW agreements, along with nonunion mines in the eastern United States, provided increasingly larger quantities of coal as the 1977 strike progressed. To help compensate for lost coal-fired generation, substantial amounts of reserve oil-generating capacity were pressed into service. Finally, during each strike, substantial amounts of electricity were purchased from other power areas.[5]

Embargo

On October 16, 1973, Organization of Arab Petroleum Exporting Countries (OAPEC) ministers unilaterally raised petroleum prices 70 percent and agreed upon monthly 5-percent production cutbacks. In early November, however, OAPEC banned all petroleum exports to the United States and imposed an effective 25-percent production cutback. In late December 1973, sales to Caribbean refineries, whose product had been redirected to U.S. markets, were also banned, although production cutbacks began to ease. During January and February 1974, allowances for other nations were progressively eased. Finally, on March 18, 1974, the embargo against the United States was lifted by all nations except Libya and Iraq.

Throughout the embargo period, only Arab (OAPEC) members of the Organization of Petroleum Exporting Countries (OPEC) supported the embargo and production cutbacks; one OAPEC member, Iran, actually increased production during the period. However, all OPEC members unanimously supported the petroleum price increases.

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[5]National Electric Reliability Council, The Coal Strike of 1977-78: Its Impact on the Electric Bulk Power Supply in North America (Princeton, New Jersey, May 1978).

Natural Gas Curtailments

Under both Federal and State regulations, demand for natural gas to heat homes and serve small business and industry takes priority over the demand of electric utilities. Consequently, during the months from November to March (the peak heating season), many electric utilities in the 1970's were on occasion denied natural gas when available pipelines reached capacity in serving heating demand.[6] During the middle 1970's, curtailments to electric utilities became more common, occasionally occurring during the nonheating season as suppliers conserved stocks in preparation for heating season demand. In the face of an attractive interstate price structure but deprived of supplies during many months of the year, utilities in the 1970's used relatively less-expensive natural gas when it was available, then switched to more expensive alternate fuels when natural gas supplies were curtailed.

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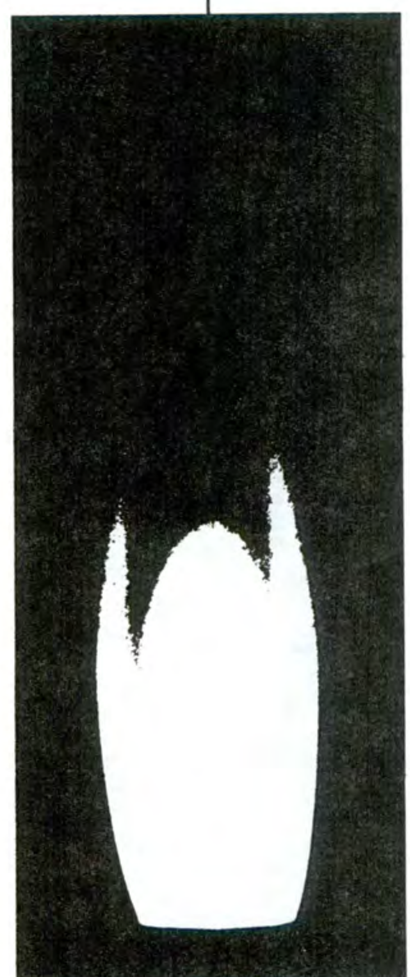
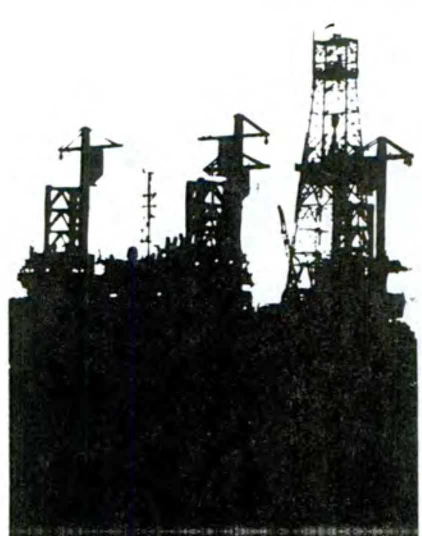
[6] To some extent, the lower prices for natural gas charged to utilities occur in exchange for the suppliers' right to curtail supplies as alternate demand increases. In effect, pipelines sell surplus capacity to utilities at low prices during the nonheating season in exchange for the right to curtail supplies during the heating season.

Fuel Choice by Region





4. Fuel Choice by Region

Introduction

This chapter reviews fuel choice by electric utilities in each of 12 regions during the period from July 1972 through December 1982 (Figure ES1). The time period chosen was determined by the availability of a consistent set of data. Prior to July 1972, key data elements were missing or available only from different and not always mutually consistent sources. Results were not updated past 1982, since changes occurring over the last 2 years would not alter the conclusions relating to short-term fuel choice decisions. The regions are based on the regional reliability councils (and certain subcouncils) of the North American Electric Reliability Council (NERC).[1] The NERC regions reflect the operational groupings of utilities, and the subregions used in this report allow concentration on specific areas that have special fuel-use characteristics. The 12 regions are defined as follows:[2]

New England	--	The New England Power Pool subregion of the Northeast Power Coordinating Council (NPCC)
New York	--	The New York Power Pool subregion of NPCC
MAAC	--	Mid-Atlantic Area Council
Southeast	--	The Southeastern Electric Reliability Council (SERC), excluding the Florida subregion
Florida	--	The Florida subregion of SERC. Note that the part of western Florida served by Gulf Power is assigned to the Southeast region. Gulf Power is a subsidiary of Southern Company and is centrally dispatched by its parent company.
ECAR	--	East Central Area Reliability Coordination Agreement
MAIN	--	Mid-America Interpool Network

[1]The North American Electric Reliability Council (NERC) was formed by the electric utility industry in 1968 to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America.

[2]Alaska and Hawaii are excluded. Hawaiian utilities use oil for 99 percent of their generation and Alaskan utilities primarily use a mix of hydroelectric, internal combustion, and combustion turbine generation. Neither State has the range of steam generation options addressed in this report.

Fuel Choice by Region

MAPP	-- Mid-Continent Area Power Pool (United States only), formerly Mid-Continent Area Reliability Coordination Agreement (MARCA)
SPP	-- Southwest Power Pool
ERCOT	-- Electric Reliability Council of Texas
Pacific Northwest	-- Northwest Power Pool Area and Rocky Mountain Power Area of the Western Systems Coordinating Council (WSCC)
Pacific Southwest	-- Arizona-New Mexico Power Area and California-Southern Nevada Power Area of WSCC. Note that the part of Texas serviced by El Paso Electric is part of the Pacific Southwest region. Northern Nevada is part of the Northwest Power Pool Area, but has no power plants; thus the State is treated as part of the Pacfic Southwest for this report.

Graphs of monthly net generation are provided in this chapter for each region.[3] The graphs show total (net) generation, net generation from hydroelectric and nuclear power plants, coal-fired steam power plants, and oil- and gas-fired steam power plants. For clarity, each fuel is graphed separately, with a common horizontal axis showing months. Labeled tick marks identify July of each year, and the unlabeled tick marks identify January of each year. Because of the small amount of generation from specific fuels in each region, the scale of the vertical axis differs on each graph and should be noted when comparing the amounts of generation from each fuel and in each region. Generation from peaking units and "other" generation (geothermal, biomass, solar, etc.) are excluded because it is such a small amount. Fossil-fuel costs, including oil, natural gas, and coal costs (in dollars per million Btu), together with the weighted average fossil-fuel cost (quantity weighted average cost using Btu of coal, oil, and natural gas delivered to the power plant), are graphed on a single graph. The horizontal axis is the same as that for generation, and a common vertical axis is used, permitting direct comparisons across regions.

Tables of annual data for each region, which supplement the monthly graphs, are provided in Appendix C. The annual data include (1) net generation by energy source, (2) fossil-fuel costs, (3) fossil-fuel steam capacity by fuel type for both single fuel and multifuel boilers, and (4) capacity utilization ratios.

[3]Net generation is defined as total generation minus plant use. Because certain types of power plants can use more electricity than they generate, net generation can be negative in certain months. Nuclear power plants have negative net generation during refueling and maintenance periods, and pumped-storage hydroelectric generators always have negative net generation over time spans as long as a month.

Fuel Choice by Region

New England

Virtually all generation in the New England region is centrally dispatched by the New England Power Exchange (NEPEX), a component of the New England Power Pool (NEPOOL).[4] Although the region has substantial hydroelectric capacity, oil has traditionally been the primary energy source (Figure 1). Coal has only recently become an important source of energy in this region. New England also imports hydroelectric and nuclear generation from Canada.[5]

Nuclear generation increased during the early part of the 1972-1982 period. Coal use was being phased out prior to 1979 but increased to a limited extent after 1979 (Appendix C). Prior to 1979, transportation costs raised the cost of coal in New England to the point where it was not a particularly attractive alternative to oil or gas. Environmental restrictions probably also had some effect in retarding the development of coal-fired generating capacity.

The decline in the use of oil as the primary energy source--from 73 percent in 1972 to 43 percent in 1982 (Appendix C)--may reflect the sharp increase in oil costs relative to other fossil fuels, especially coal (Figure 2). After 1979, the jump in oil costs apparently provided incentives to reduce oil-fired generation; however, there were few options for doing so quickly. Coal, nuclear, and hydroelectric capacity were limited and could not be increased immediately because building such power plants requires several years. In addition, environmental and political opposition, high interest rates, and the safety-related concerns that followed the Three Mile Island (TMI) episode all made construction of new coal-fired and nuclear-powered plants both more costly and more time-consuming. Natural gas was not an attractive alternative to oil because of limits on natural gas transmission capacity, competing demand, and high costs. Importing electricity from Canada and from other U.S. regions is an ongoing alternative.[6] These imports of hydroelectric, coal-fired, and nuclear-powered generation reduced the growth in total generation and meant that there would be little or no growth in oil-fired generation. In 1982, more intensive use of existing coal capacity and the addition of more gas-fired capacity seem to have reduced oil-fired generation (Appendix C).

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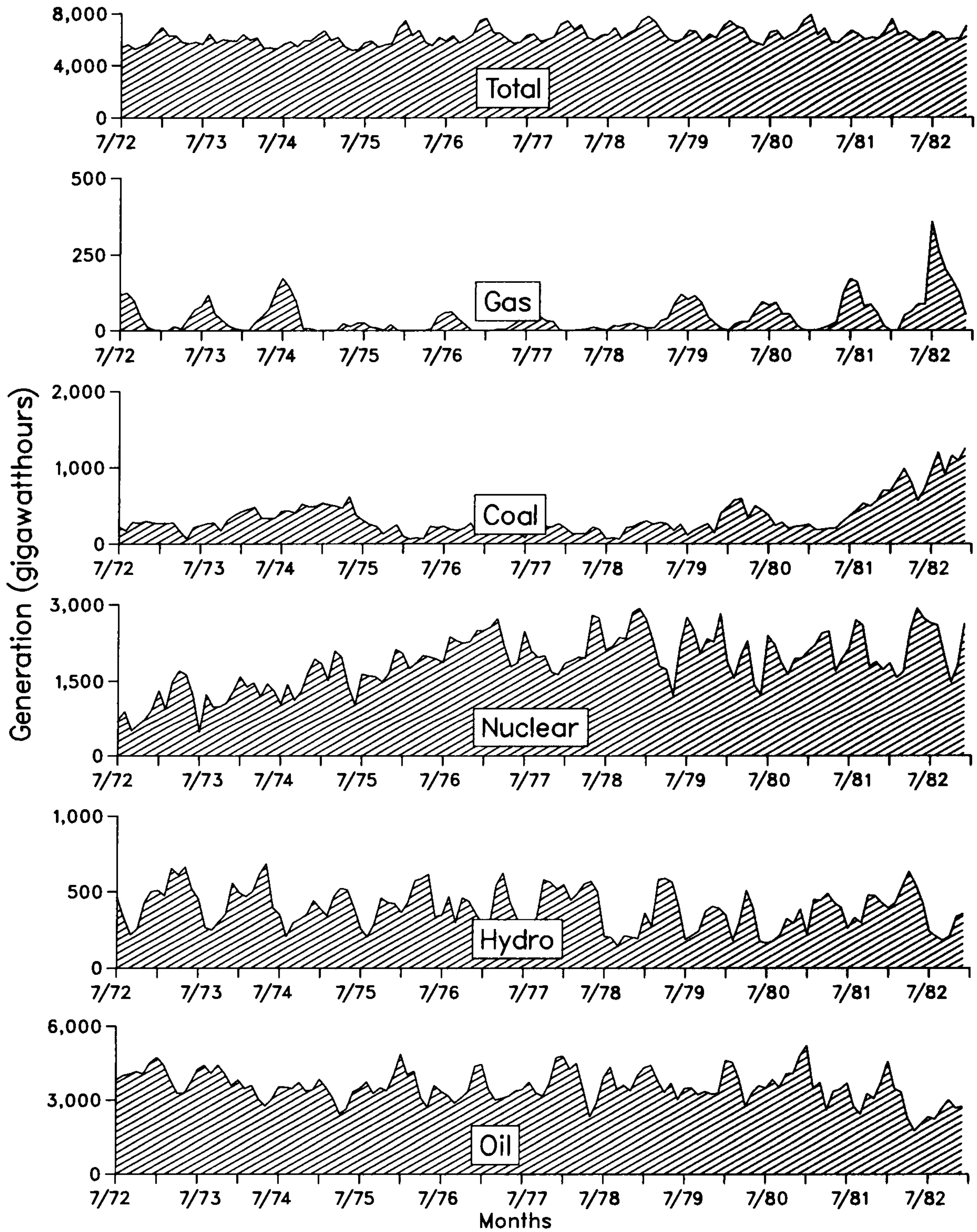
[4]Federal Energy Regulatory Commission, Power Pooling in the Northeast Region, FERC-0050 (Washington, DC, 1981). Maine Public Service Company is the only generating utility in the region that does not belong to NEPOOL. The "Yankee" nuclear power plants are owned by corporate entities that are, in turn, owned by various NEPOOL-member utilities.

[5]Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, U.S.-Canadian Electricity Trade, DOE/EIA-0365 (Washington, DC, November 1982).

[6]Energy Information Administration, U.S.-Canadian Electricity Trade.

Fuel Choice by Region

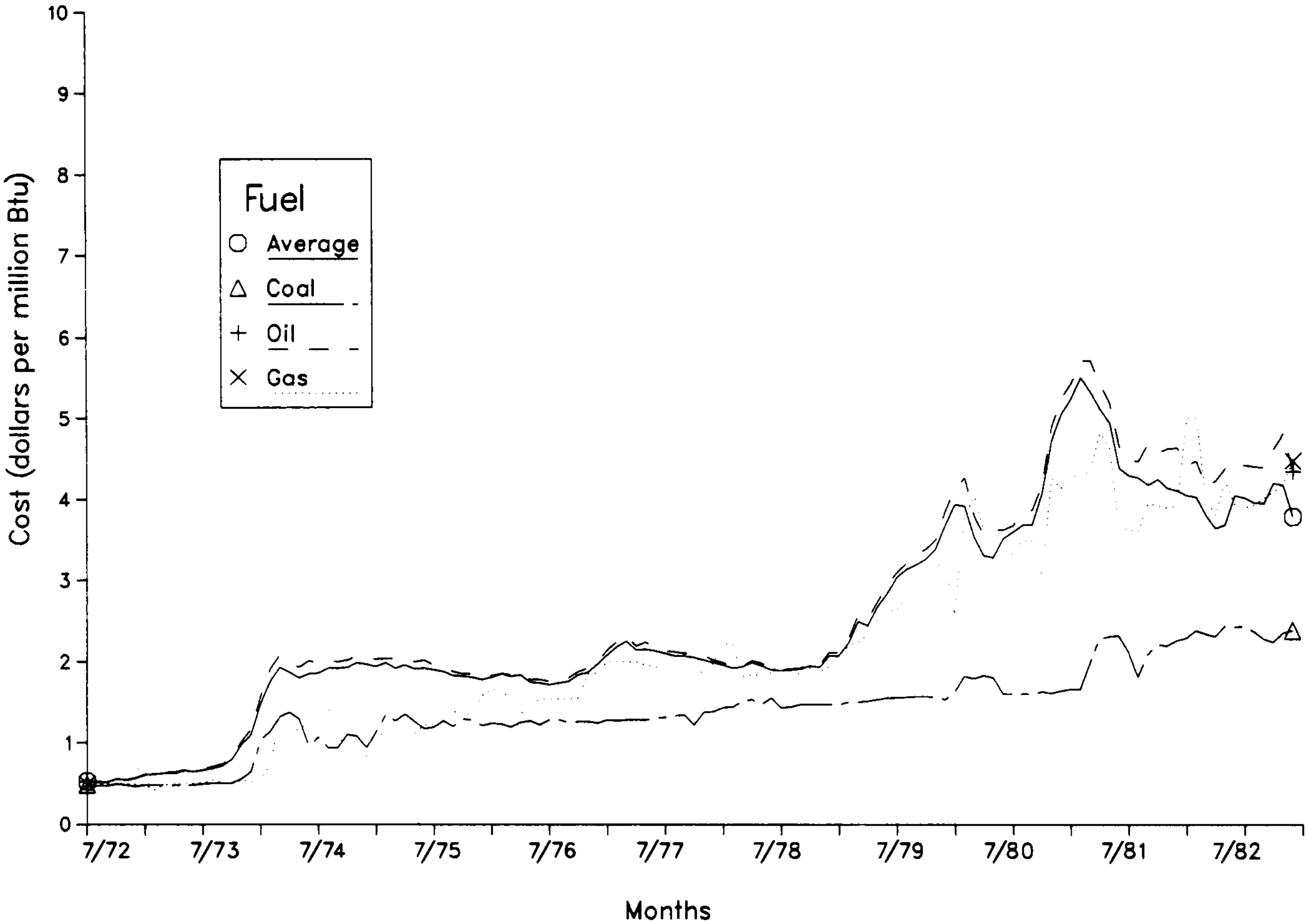
Figure 1. Net Generation by Energy Source in the New England Region, July 1972-December 1982



Note: Scale for vertical axis differs for each energy source.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Fuel Choice by Region

Figure 2. Fossil-Fuel Costs in the New England Region, July 1972-December 1982



Note: Average is the quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plant.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuel for Electric Plants," and predecessor forms.

Fuel Choice by Region

New York

Most utilities in the New York region belong to the New York Power Pool (NYPP), a centrally dispatched power pool.[7] The major exception, the Power Authority of the State of New York (PASNY), participates in NYPP committee activities, although it is not a formal member.

The New York region has abundant hydroelectric resources, especially on the St. Lawrence River. Such run-of-the-river hydroelectric sites do not depend on reservoirs or other methods of storing the water used to generate electricity, and are less affected by seasonal factors or rainfall. Thus, hydroelectric generation is a reliable source of baseload power in the New York region. The region also has abundant coal capacity available, and ample opportunity to purchase Canadian coal-fired and hydroelectric generation. In addition, upstate New York is winter-peaking while New York City is summer-peaking. Even so, New York City (the principal regional load center) still depends largely on oil-fired steam and peaking generation, mainly because of limited transmission capacity.

Current levels of bulk power transfers have pushed transmission capacity to the limits of reliability. Increasing power transfers to exploit the most economical existing generating capacity would require expanding the capacity of the transmission system, either by building additional transmission lines or by upgrading (reinforcing) existing lines. The New York utilities have developed plans to expand transmission system capacity, but this projected expansion is not reflected in this report.[8]

In the New York region from July 1972 through December 1982, oil-fired steam remained the principal generation source, with hydroelectric generation second. Nuclear generation increased in the first half of the 1970's so that from about 1975 onward, coal and nuclear power provided approximately the same level of generation. Gas-fired generation fell between 1972 and 1978, but increased sharply after 1978. An apparent seasonal pattern existed for natural gas use, with a decline during winter months (Figure 3).

In the New York region, natural gas costs were lower than coal costs until after 1976, when gas became more expensive than coal (Figure 4). By 1982, natural gas cost approximately twice as much as coal. Environmental constraints on adding new coal capacity, especially in the southern part of the region, and constraints imposed by the existing transmission systems led to continued reliance on oil as a principal energy source. In fact, the only increase in fossil-fueled capacity during the period was oil-fired. Coal- and gas-fired capacity actually fell (Appendix C). The 1979 oil cost increase gave the utilities added incentive to find alternatives to oil. Effectively, natural gas use was the only available alternative because coal use was limited by environmental and transmission system constraints and because building additional nuclear capacity required time.

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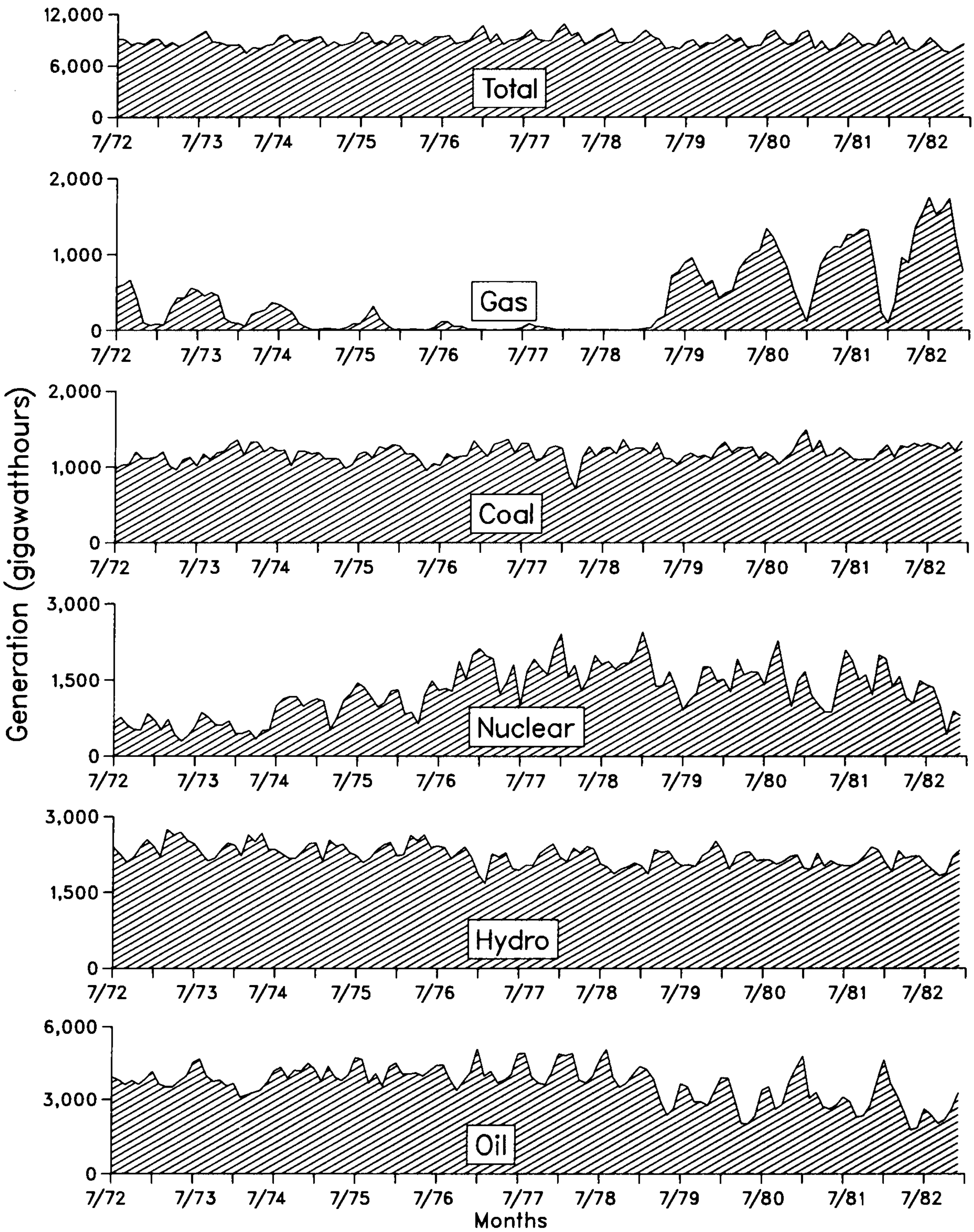
[7] Federal Energy Regulatory Commission, Power Pooling in the Northeast Region, FERC-0050 (Washington, DC, 1981).

[8] North American Electric Reliability Council, Impediments to Transfers, Report for the Association of Regulatory Commissions (Princeton, New Jersey, May 1984).

Fuel Choice by Region

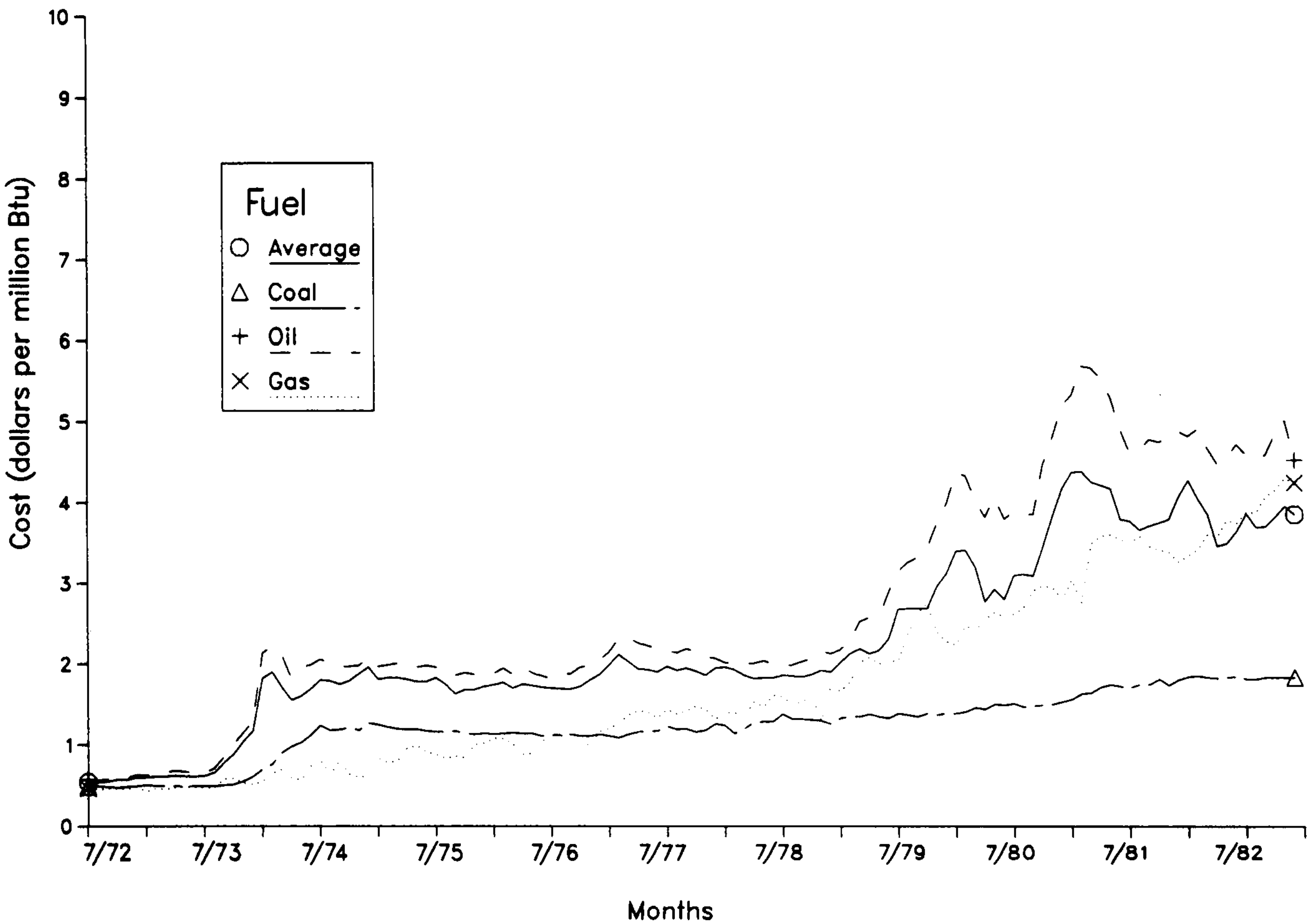
Figure 3. Net Generation by Energy Source in the New York Region, July 1972-December 1982



Note: Scale for vertical axis differs for each energy source.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Fuel Choice by Region

Figure 4. Fossil-Fuel Costs in the New York Region, July 1972-December 1982



Note: Average is the quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plant.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuel for Electric Plants," and predecessor forms.

Fuel Choice by Region

MAAC

The MAAC region is the third region that is effectively a single, centrally dispatched power pool, in this case, the Pennsylvania-New Jersey-Maryland Interconnection (PJM). During most of the 1972-1982 period, the majority of generating utilities in MAAC belonged to PJM. Those generating utilities that were not signatories to the PJM agreement participated in the pool's coordinated operation through separate agreements with pool members.[9]

MAAC has a wide mix of generator types (Figure 5). In 1972 and 1973, coal- and oil-fired units provided the bulk of generation, then in 1974, nuclear-powered generation increased substantially. Throughout the period, coal was the principal fuel. Nuclear power and oil use followed closely, providing approximately equal amounts of generation until 1979.

There was a marked change in 1979. Oil-fired generation began a decline that continued through 1982. Nuclear generation also declined in 1979 after the Three Mile Island (TMI) incident, but picked up again in 1981. In part, the decrease in oil-fired generation following 1979 was offset by increased gas-fired and nuclear-powered generation. The rest of the decrease, however, was not compensated for by any fuel source in the MAAC region, and total generation declined from the 1978 peak. However, total electricity consumption did not fall in this region; instead, there was a substantial increase in purchased power (primarily coal-fired) from the neighboring ECAR and Southeast regions.[10]

The persistence of oil-fired generation despite the 1979 oil cost increase (Figure 6) may have been due to limited available transmission capacity from coal-fired generators in western Pennsylvania (and from coal-fired generators in the neighboring ECAR region, which provides bulk power sales to MAAC) and from load centers along the Washington, DC-Baltimore-Philadelphia corridor.[11] The expansion of nuclear generation also had complications. The TMI nuclear power plant, which is located in MAAC, not only provides substantial generation, but is strategically

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[9]Federal Energy Regulatory Commission, Power Pooling in the Northeast Region, FERC-0050 (Washington, DC, 1981). By 1982, these utilities had, in fact, signed the PJM agreement. Several small generating municipal and cooperative utilities are associate members of MAAC, but not a part of PJM.

[10]In 1982, MAAC imported approximately 13.1 percent of total energy for load. North American Electric Reliability Council, 1982 Annual Report, (Princeton, New Jersey) p. 14.

[11]North American Electric Reliability Council, 14th Annual Review of Overall of Overall Reliability and Adequacy of Bulk Power Supply in the Electric Utility Systems of North America (Princeton, New Jersey, 1984), pp. 17-18. This report shows that in 1982 the most limiting transmission facilities in MAAC were loaded to 100 percent of their capability 40 percent of the time and to 90 percent or more of their capability 65 percent of the time.

Fuel Choice by Region

located in the transmission grid. Loss of its generation following the 1979 incident reduced west-to-east transmission capacity.[12]

The most obvious monthly fossil-fuel cost changes for the MAAC region were the 1979 oil cost increase and the increase in natural gas costs that followed (Figure 6). Coal costs also rose after the 1979 oil cost increase, but not as dramatically. In fact, coal costs continued to increase even when oil costs began to decline in late 1981 and 1982. Natural gas costs, especially prior to 1979, show considerable volatility probably attributable to the seasonal nature of its use by the utilities and by disruptions in its supply.

Coal strikes, especially the record-length strike in the winter of 1977-1978, appeared to have disrupted fuel-use patterns in the MAAC region. During most strikes, oil-fired generation replaced lost coal-fired generation, supplemented by purchases from other regions. The availability of oil capacity probably accounted for the ability of the MAAC region to sell power to other regions during the strike (Appendix C).

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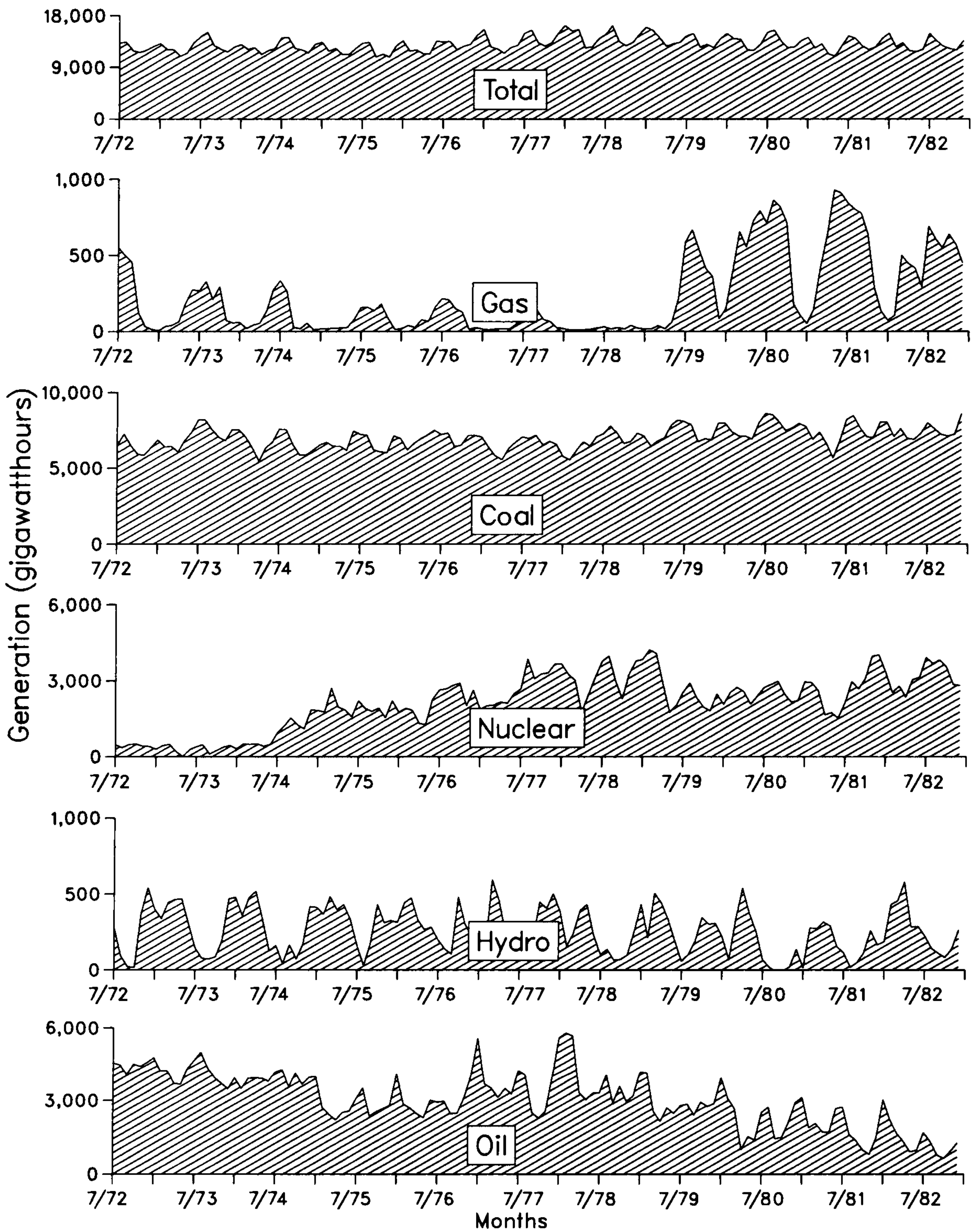
[12]Generation from TMI was used to supply reactive load to bolster and stabilize transmission from western Pennsylvania power plants.

Fuel Choice by Region

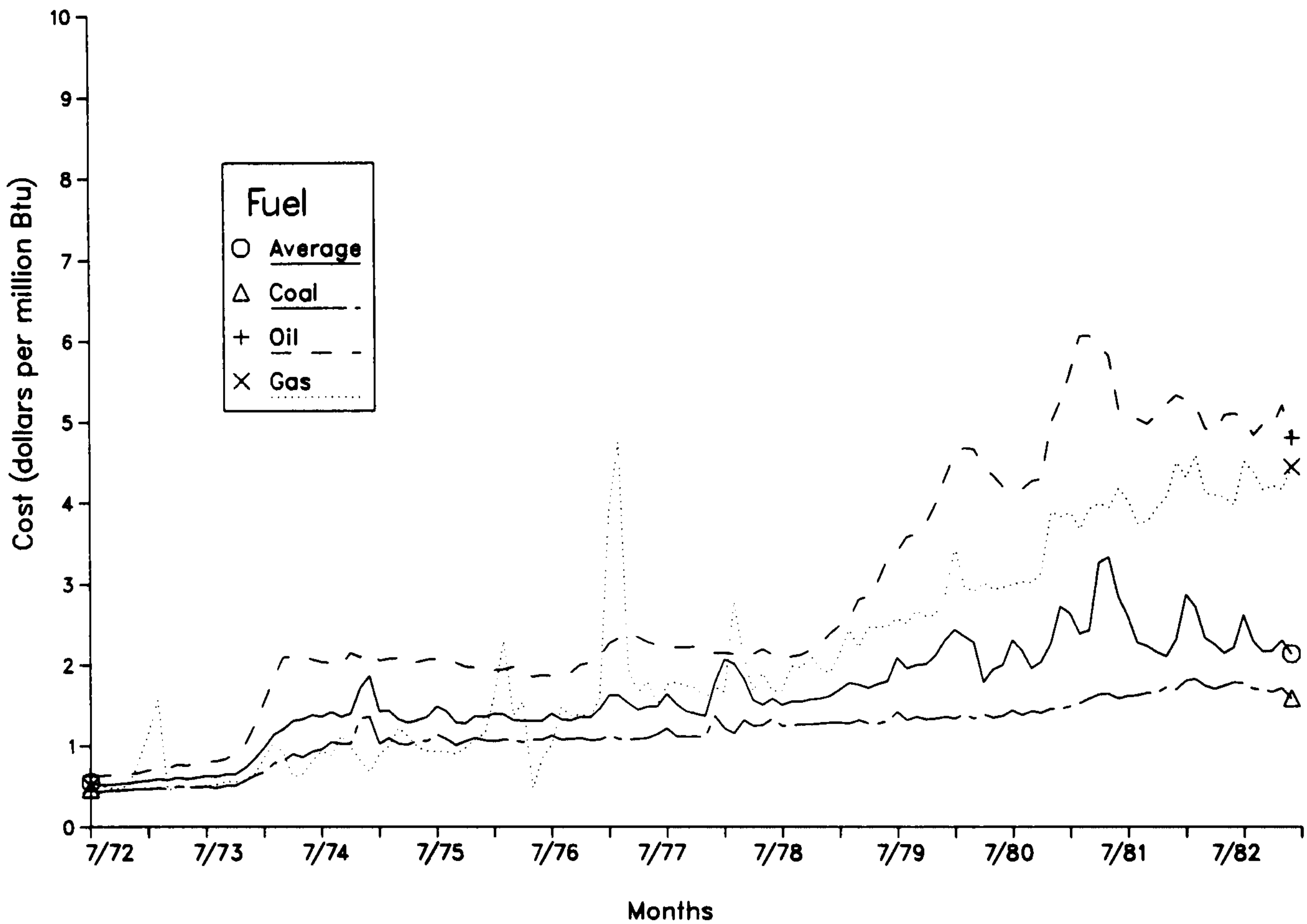
Figure 5. Net Generation by Energy Source in the MAAC Region, July 1972-December 1982



Note: Scale for vertical axis differs for each energy source.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Fuel Choice by Region

Figure 6. Fossil-Fuel Costs in the MAAC Region, July 1972-December 1982



Note: Average is the quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plant.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuel for Electric Plants," and predecessor forms.

Fuel Choice by Region

Southeast

For this report, the Southeastern Electric Reliability Council (SERC) has been divided into the Florida and Southeast regions. The Southeast region, which includes the Tennessee Valley Authority,[13] uses coal as its primary energy source for electricity generation (Figure 7). Nuclear and hydroelectric generation are also important factors. Oil-fired generation (restricted primarily to Virginia) diminished in importance following the 1979 cost jump, while natural gas was never a major energy source in the region. The growth in total demand was largely met by increased nuclear generation as hydroelectric and coal-fired generation showed relatively little growth, and oil- and gas-fired generation declined.

Oil-fired generation declined at about the same time as the 1979 increase in oil cost (Figure 8). The extent to which Southeast utilities were able to displace oil- and gas-fired generation after 1979 (including peaking generation) suggests that the region's generating capacity mix and transmission capacity allows for more efficient dispatch than, for example, the New England, New York, or MAAC regions, where limited transmission capacity restricts efficient dispatch.[14]

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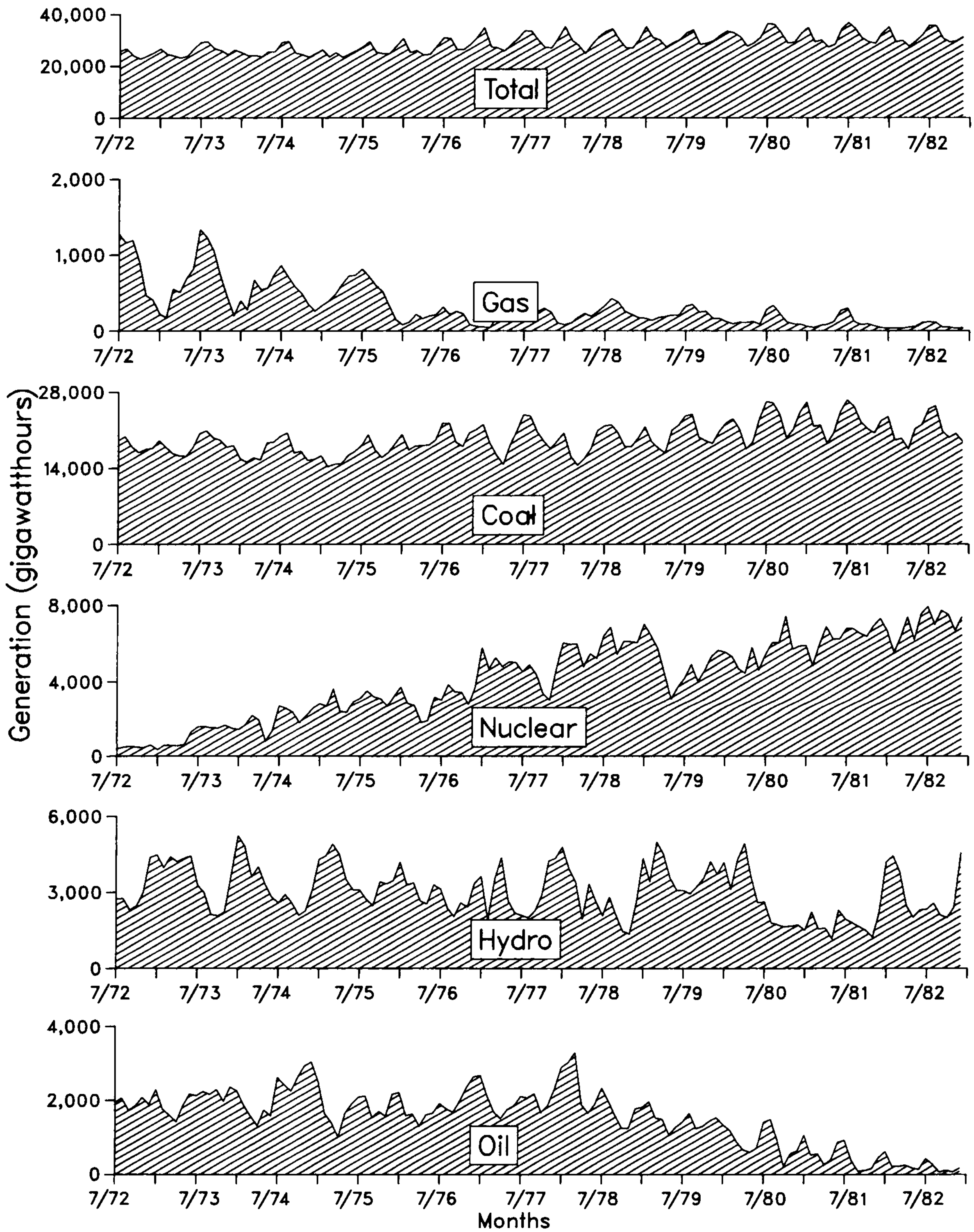
[13] Federal Energy Regulatory Commission, Power Pooling in the Southeast Region, FERC-0051 (Washington, DC, 1981).

[14] Virginia Electric and Power Company (VEPCO), the principal oil-using utility, was able to reduce oil-fired generation substantially by buying nuclear or coal-fired generation from other Southeast utilities and from the ECAR region. North American Electric Reliability Council, 14th Annual Review of Overall Reliability and Adequacy of Bulk Power Supply in the Electric Utility Systems of North America (Princeton, New Jersey, 1984), p. 49. VEPCO has also undertaken an extensive program of converting oil-fired units to coal-burning units.

Fuel Choice by Region

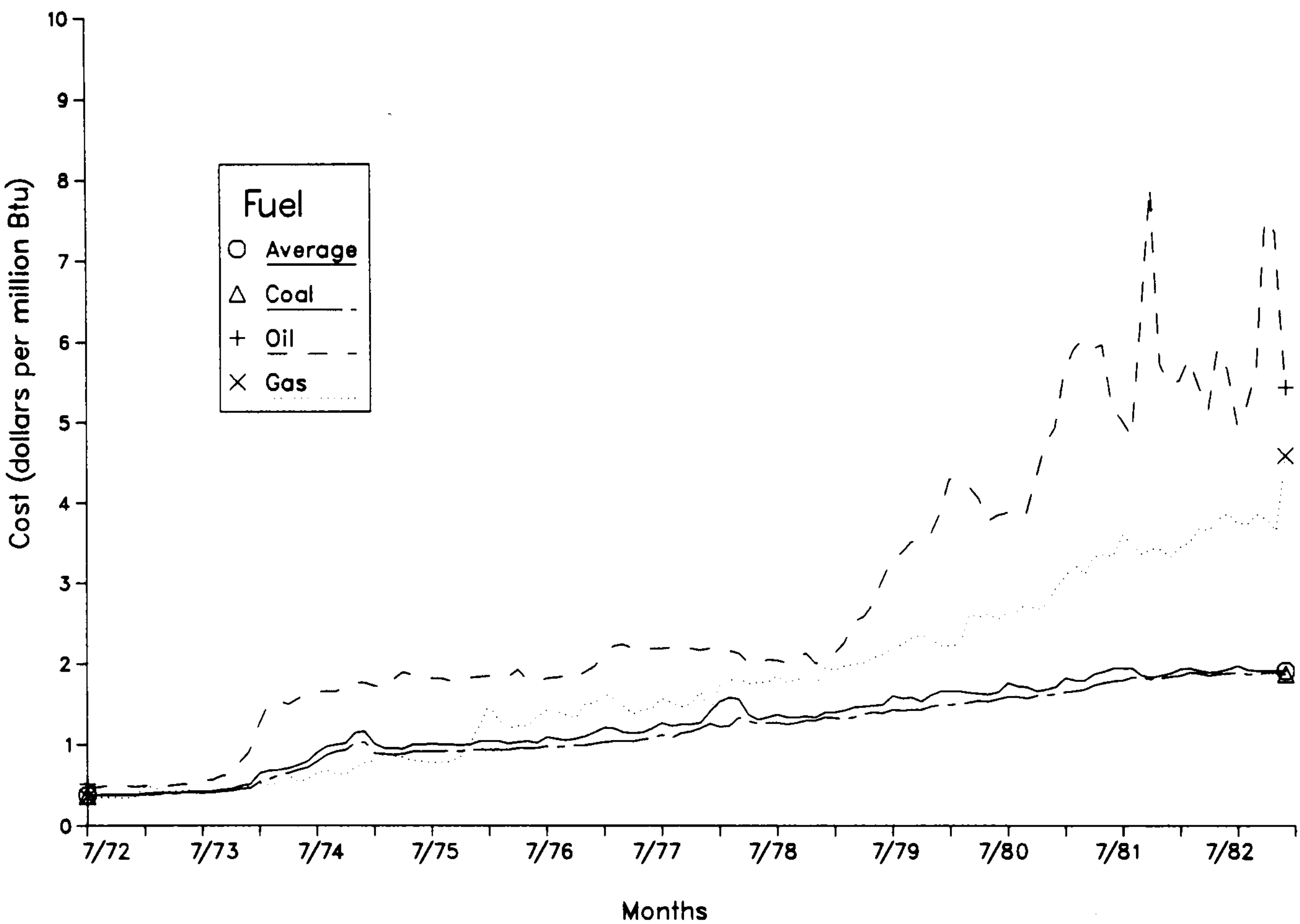
Figure 7. Net Generation by Energy Source in the Southeast Region, July 1972-December 1982



Note: Scale for vertical axis differs for each energy source.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Fuel Choice by Region

Figure 8. Fossil-Fuel Costs in the Southeast Region, July 1972-December 1982



Note: Average is the quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plant.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuel for Electric Plants," and predecessor forms.

Fuel Choice by Region

Florida

Because Florida is a peninsula, interconnections between utilities within and outside of Florida are limited to a corridor of north-south transmission lines into the Southeast region.[15] Limited capacity on the tie lines from the rest of SERC has made Florida more autonomous electrically than other regions.[16]

Florida has a unique energy broker arrangement that facilitates interutility bulk power transactions.[17] This permits more efficient dispatch of regional capacity by allowing utilities to displace high-cost generation from their own power plants with lower-cost generation from other utilities' power plants. Existing capacity still limits the savings that can be achieved by improved coordination, since Florida depends on oil and gas for most of its generation.

There is a pronounced seasonal pattern in electric load in Florida, caused by extensive air conditioning use during the summer. Oil-fired generation has sharp peaks during the summer and declines dramatically in the winter. Coal and gas usage tends to be more stable.

Oil- and gas-fired generation was relatively stable in Florida with added coal and nuclear generation providing for the increase in total generation until 1976 (Figure 9). The oil share declined after 1976 while coal and nuclear shares increased (Appendix C). Nuclear generation increased substantially, especially in 1977 when oil-fired generation fell appreciably.

Coal costs are higher while oil and gas costs are lower in Florida than in the Southeast region (Appendix C), which may explain why coal was not a larger factor in Florida. Even more noteworthy is that natural gas costs remained below coal costs until 1982, when they became essentially equal (Figure 10). These cost differences were probably due to transportation costs. Coal must be shipped into

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[15] Federal Energy Regulatory Commission, Power Pooling in the Southeast Region, FERC-0051 (Washington, DC, 1981).

[16] In 1982, completion of three additional tie lines between Florida and the Southern subregion of SERC expanded capacity from 500 MW to 1,925 MW. During the period 1972-1982, however, tie-line capacity remained limited. See North American Electric Reliability Council, 14th Annual Review of Overall Reliability and Adequacy of Bulk Power Supply in the Electric Utility Systems of North America (Princeton, New Jersey, 1984), p. 38.

[17] The Florida energy broker in fact is based on bilateral arrangements, but uses the automated matching of buy/sell offers to arrange transactions that would otherwise be arranged directly by utility-to-utility telephone or teletype. See Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, Interutility Bulk Power Transactions: Description, Economics, and Data, DOE/EIA-0418 (Washington, DC, 1983), pp. 26-27. See also Research Planning Associates, Inc., "Power Pooling: Issues and Approaches" (report commissioned by the Systems Coordination Branch), Economic Regulatory Administration, U.S. Department of Energy, 1979, Chapter 7; and Federal Energy Regulatory Commission, Power Pooling in the Southeast, Chapter 7.

Fuel Choice by Region

Florida by rail, while oil and gas can be shipped by pipeline or by sea from Gulf Coast or Caribbean refiners. Transportation costs could have reduced the relative cost advantage of coal, at least until the 1979 oil cost hikes.[18] Natural gas costs used in this report are delivered costs to the power plant and probably are lower than the cost at which additional gas would have been available. Discounts during nonwinter months and for interruptible contracts produced low costs, but at constrained levels of supply. Increased volume and firm contracts (which would be necessary for baseload gas-fired generation) would have raised gas costs, perhaps substantially. Limits on available gas pipeline capacity would also have restricted increases in gas use by electric utilities.

Also, Florida utilities did experience some curtailments of interruptible gas and had to assume that the threat of further curtailments would remain for the foreseeable future. The lack of reliable gas supplies would have made gas an unacceptable alternative to oil for baseload generation. Gas-fired generation was used, therefore, when available. Oil-fired generation remained the primary baseload source and the alternative source if gas supplies were curtailed. After the 1979 oil cost increase, the incentives to replace oil became much stronger. Coal-fired generation increased, as did gas-fired generation. Increases in gas-fired generation were made easier by the general increase in gas supplies, but still restricted by gas pipeline capacity and the discontinuity in gas pricing.

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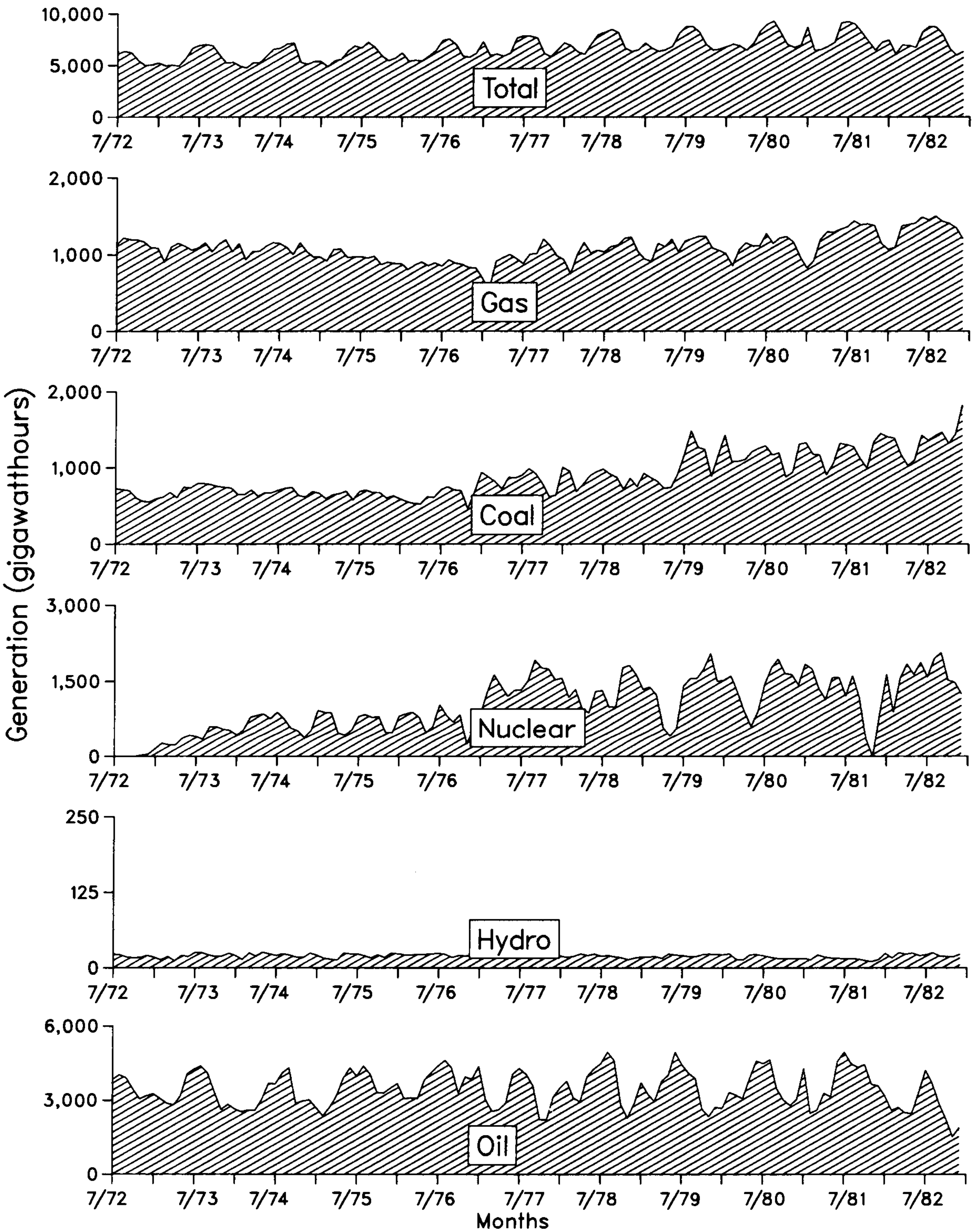
[18] Because of the higher cost per unit of capacity of coal-fired plants, oil and gas costs must be much higher than coal costs to justify the investment in new coal-fired power plants.

Fuel Choice by Region

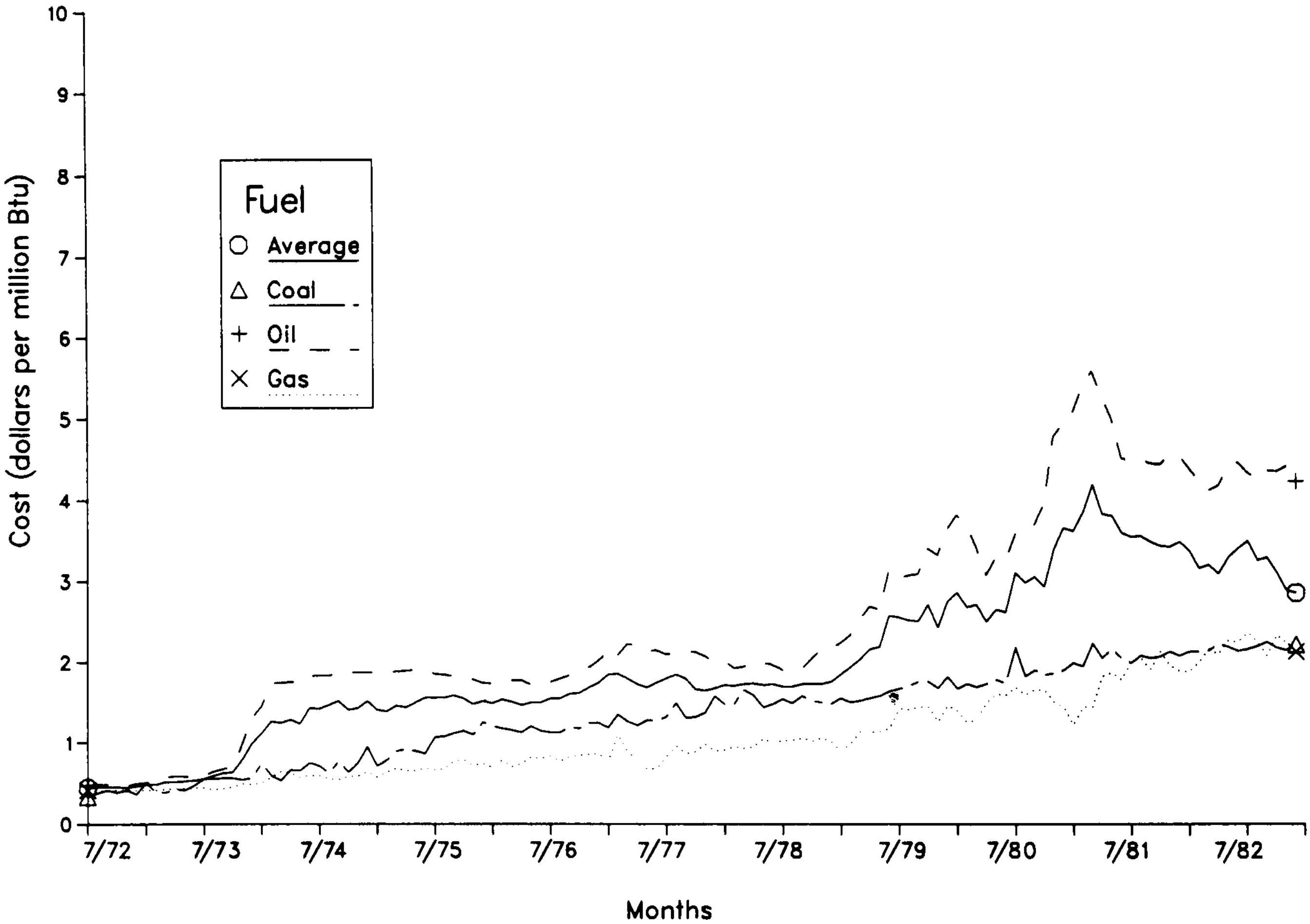
Figure 9. Net Generation by Energy Source in the Florida Region, July 1972-December 1982



Note: Scale for vertical axis differs for each energy source.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Fuel Choice by Region

Figure 10. Fossil-Fuel Costs in the Florida Region, July 1972-December 1982



Note: Average is the quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plant.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuel for Electric Plants," and predecessor forms.

Fuel Choice by Region

ECAR

The ECAR region uses coal as its primary energy source, with other fuels combined providing less than 10 percent of total generation (Appendix C).[19] Nuclear generation became a factor in total generation in the mid-1970's, but still remained a minor component (Figure 11). Hydroelectric, oil-, and gas-fired generation all played minor roles in electricity supply over the entire period. Oil-fired generation increased substantially from December 1977 to March 1978, most likely in response to the coal strike at that time (Figure 11). The decline in coal-fired generation for February and March 1978 may reflect the strike's continuation beyond the point at which utilities' coal stockpiles became dangerously low. Federal policy and the threat of shortages, combined with initially low levels of gas-fired generation, led to the virtual disappearance of gas-fired generation in this region.

One reason for coal's prominence in the ECAR region is its abundance in West Virginia, western Pennsylvania, and other parts of the region, indicating the cost advantage of local sources. Coal is consistently the cheapest fossil fuel, and after 1974, the price disparity increased, especially for oil (Figure 12).

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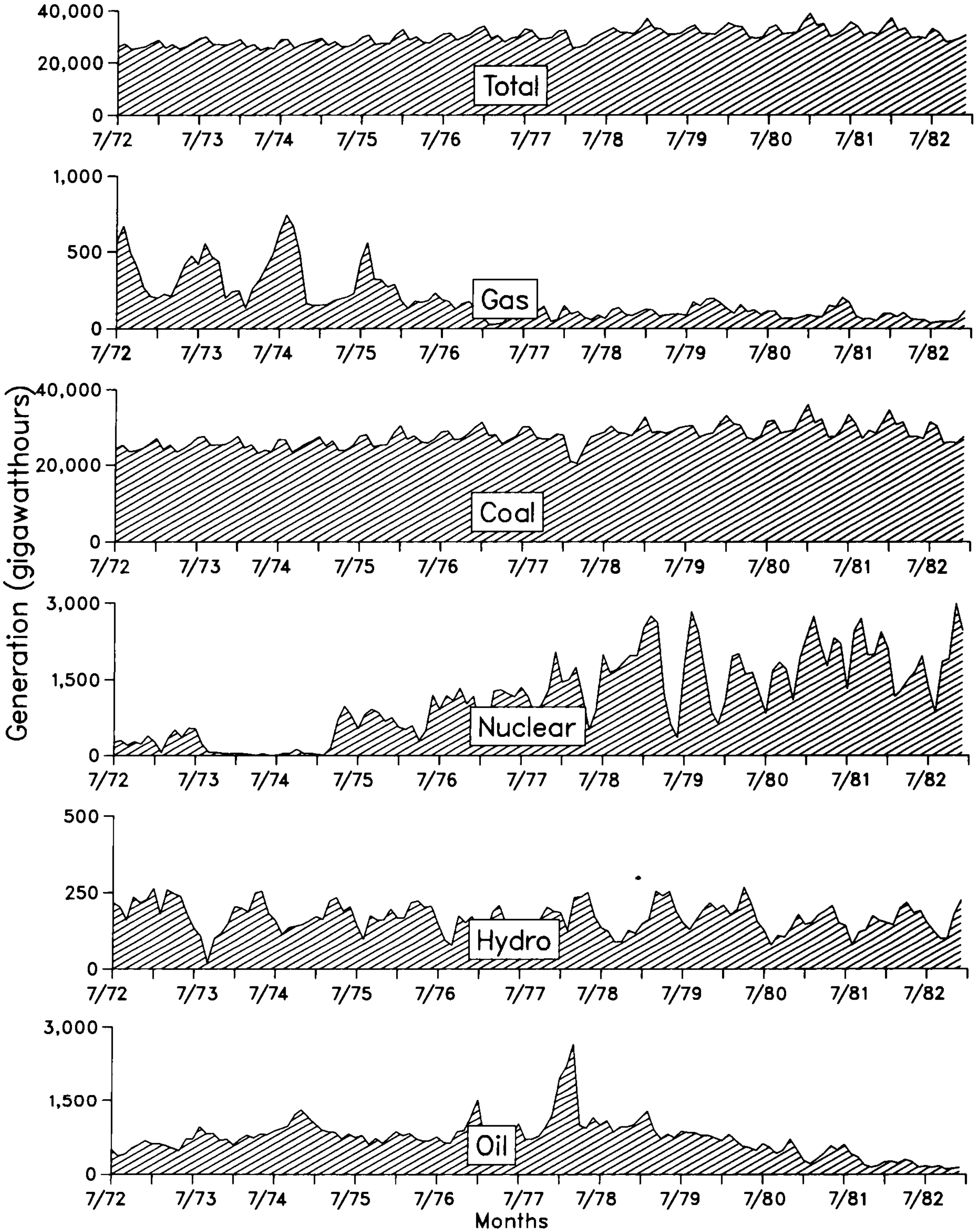
[19]For a general description of ECAR, see Federal Energy Regulatory Commission, Power Pooling in the North Central Region, FERC-0053 (Washington, DC, 1981).

Fuel Choice by Region

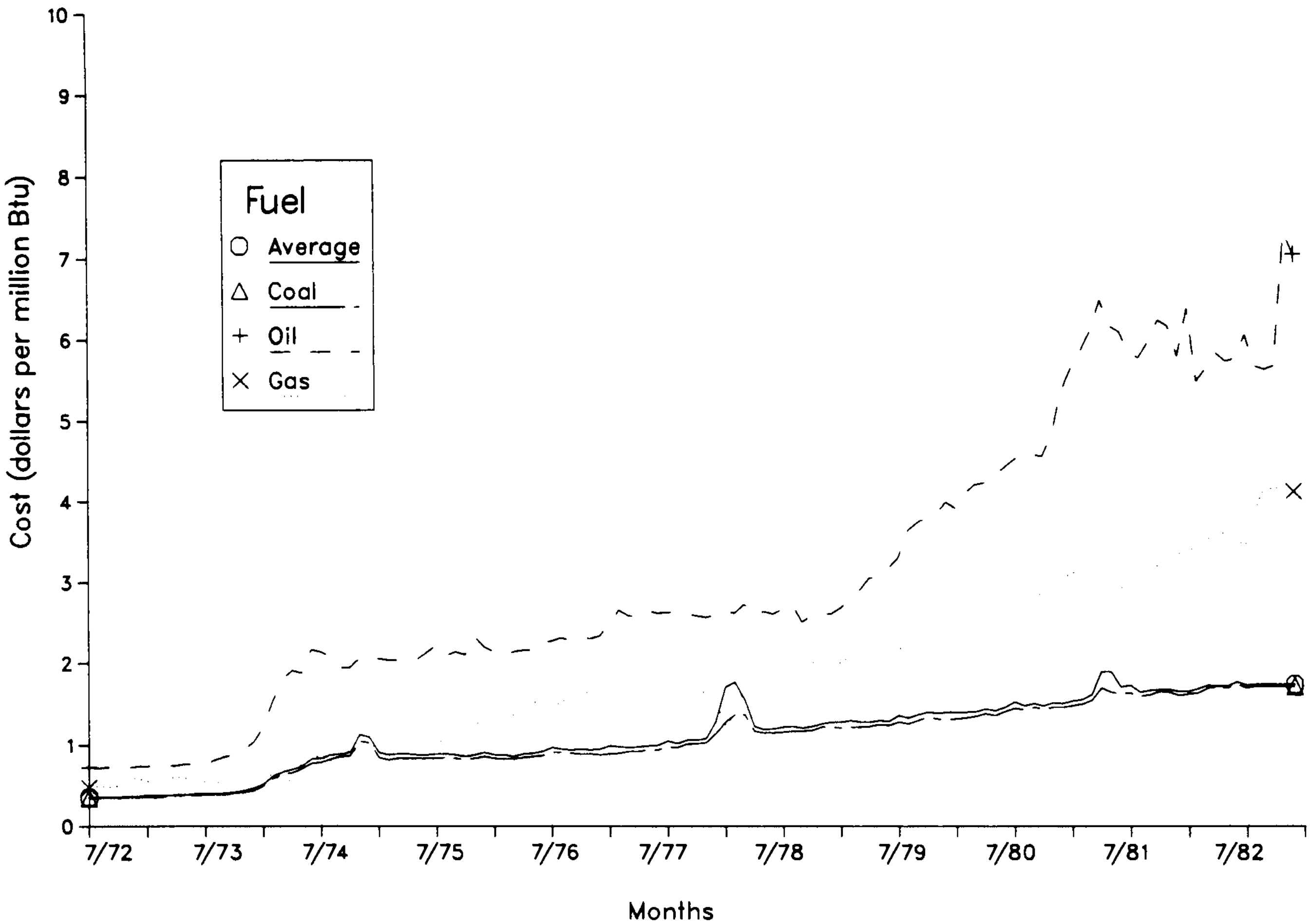
Figure 11. Net Generation by Energy Source in the ECAR Region, July 1972-December 1982



Note: Scale for vertical axis differs for each energy source.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Fuel Choice by Region

Figure 12. Fossil-Fuel Costs in the ECAR Region, July 1972-December 1982



Note: Average is the quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plant.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuel for Electric Plants," and predecessor forms.

Fuel Choice by Region

MAIN

Coal is the primary energy source for electricity generation in the MAIN region.[20] Nuclear generation supplies most of the remaining generation. In fact, nuclear generation has been a major component of total generation since before 1972 (Figure 13). Hydroelectric, oil, and gas were minor components of electricity generation for the entire period.

Single-fuel capacity (except for gas-fired steam) increased between 1972 and 1982, while multifuel coal capacity declined, as did multifuel oil and gas capacity (Appendix C). Apparently a substantial quantity of multifuel capacity capable of burning coal was converted to coal only.

Hydroelectric and oil- and gas-fired generation were used for seasonal, cycling, and peaking loads and to supplement coal-fired and nuclear generation locally. The continued use of oil-fired generation even after the 1979-1980 cost increase (Figure 14) can be attributed to technical requirements for meeting cycling loads, as nuclear and coal-fired power plants are not suited to cycling. Gas-fired generation declined even during the summer when surplus pipeline capacity made natural gas economical. The fact that gas was phased out as a fuel instead of the more expensive oil suggests that policy considerations and the potential for shortages were the deciding factors in switching away from natural gas.

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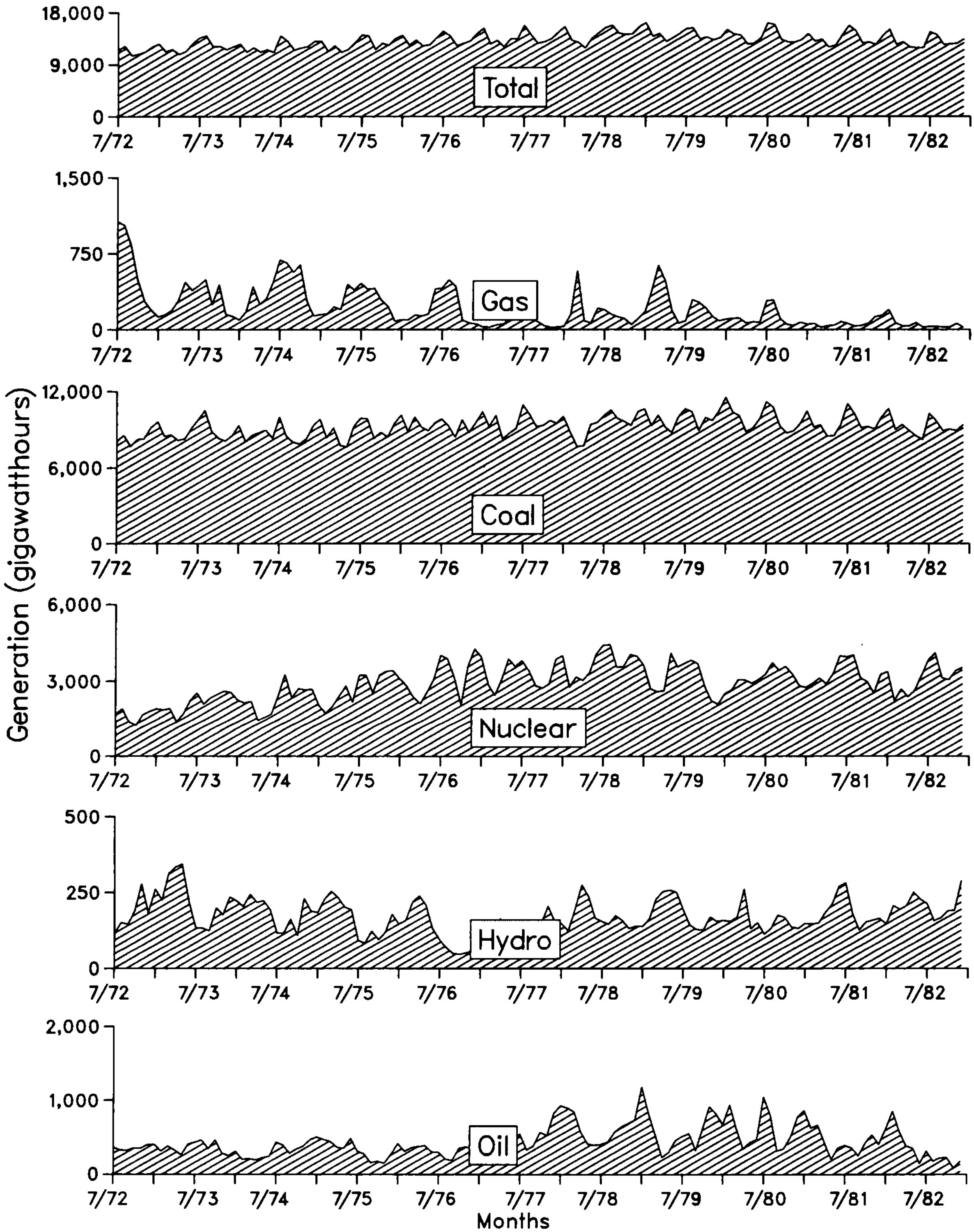
[20]For a general description of MAIN, see Federal Energy Regulatory Commission, Power Pooling in the North Central Region, FERC-0053 (Washington, DC, 1981).

Fuel Choice by Region

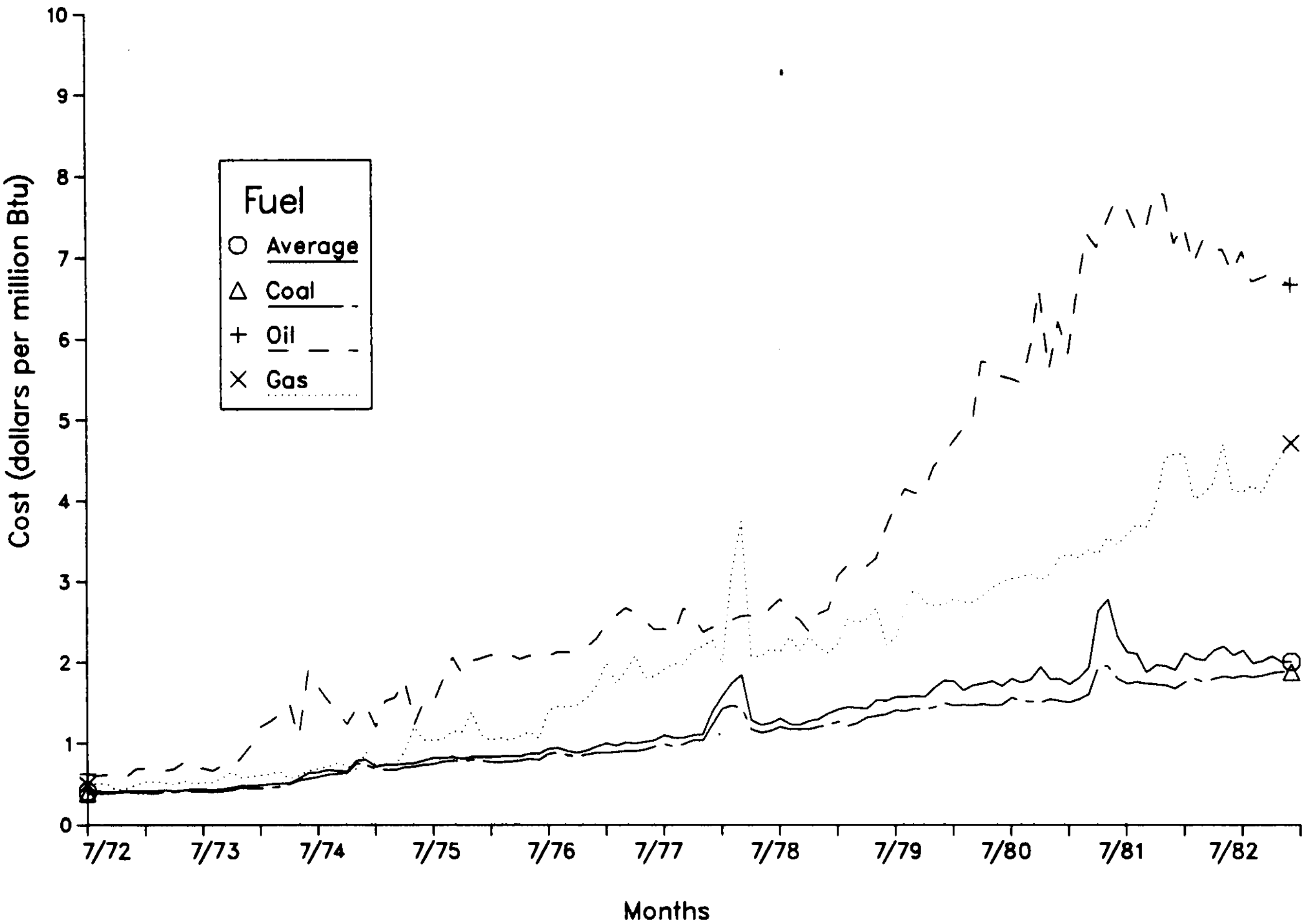
Figure 13. Net Generation by Energy Source in the MAIN Region, July 1972-December 1982



Note: Scale for vertical axis differs for each energy source.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Fuel Choice by Region

Figure 14. Fossil-Fuel Costs in the MAIN Region, July 1972-December 1982



Note: Average is the quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plant.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuel for Electric Plants," and predecessor forms.

MAPP

The MAPP region showed a major increase in coal-fired generation from 1972 through 1982 (Figure 15).[21] Gas-fired generation, an important component of total generation in the beginning of the period, fell virtually to zero by 1982. Nuclear generation remained stable after 1975, while hydroelectric generation was stable over the whole period, subject only to fluctuating water availability. Oil, always a minor component of generation within the region, declined to less than 1 percent of total generation in 1982 (Appendix C). The share of gas-fired generation fell from 20 percent in 1973 to less than 1 percent in 1982.

In part, increasing nuclear generation may account for the decrease in gas use. It is likely, however, that natural gas curtailments and the threat of a shortage encouraged the utilities to phase out natural gas as a source of generation. Then, when natural gas costs did increase, it was relatively easy to eliminate its use except for peaking or for start-up and flame stabilization in coal-fired boilers. The 1979 oil cost increase provided the necessary incentive to reduce consumption of oil, especially since coal-fired generation was an available alternative (Figure 16).

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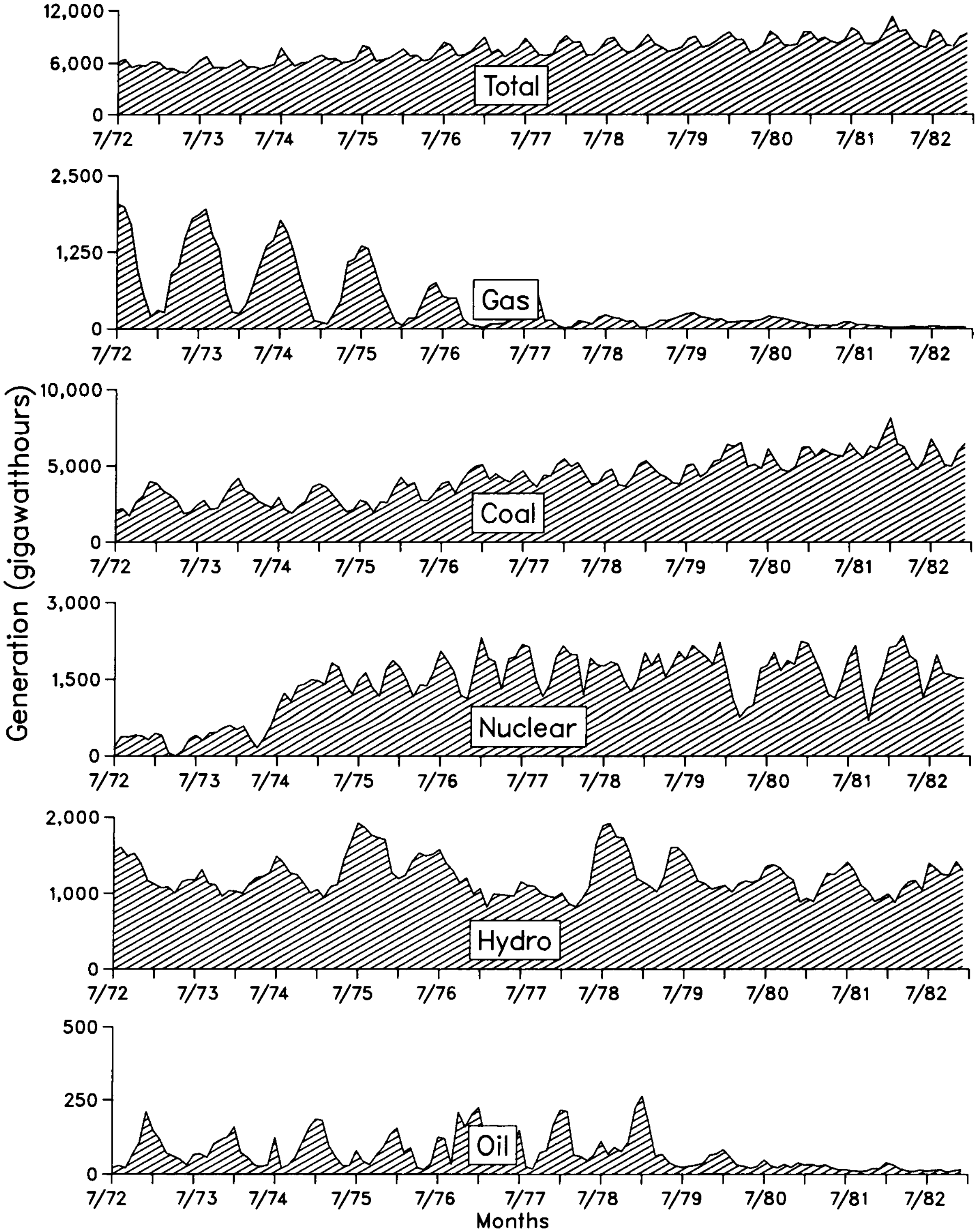
[21]For a general description of MAPP, see Federal Energy Regulatory Commission, Power Pooling in the North Central Region, FERC-0053 (Washington, DC, 1981).

Fuel Choice by Region

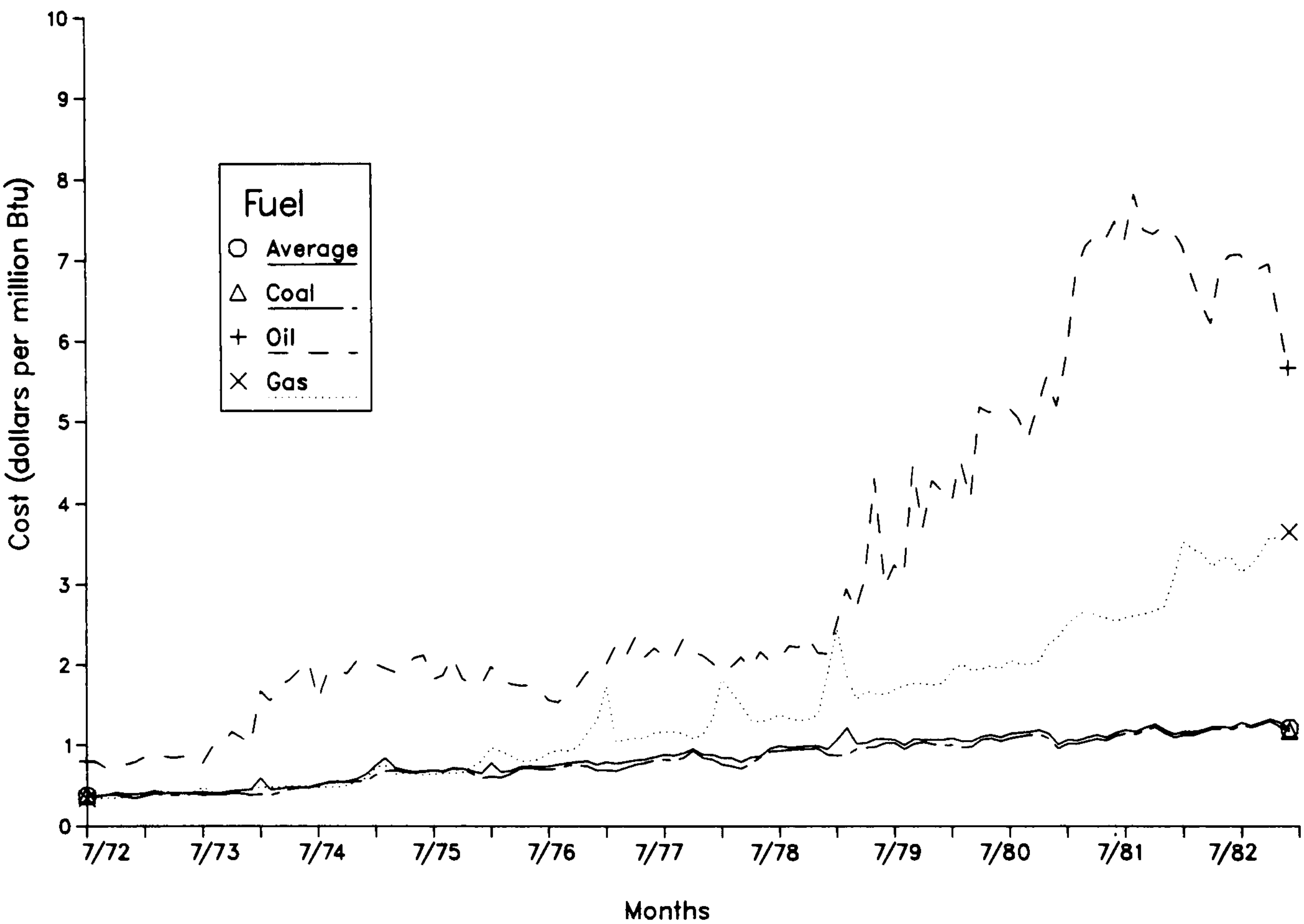
Figure 15. Net Generation by Energy Source in the MAPP Region, July 1972-December 1982



Note: Scale for vertical axis differs for each energy source.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Fuel Choice by Region

Figure 16. Fossil-Fuel Costs in the MAPP Region, July 1972-December 1982



Note: Average is the quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plant.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuel for Electric Plants," and predecessor forms.

Fuel Choice by Region

SPP

There are three subregions in SPP (Missouri-Kansas, Oklahoma, and Arkansas-Louisiana), each with different load and generating characteristics.[23] Missouri-Kansas is and has been primarily coal-using, while Arkansas-Louisiana is primarily gas-using. The Oklahoma subregion started the 1972-1982 period depending primarily on gas with a shift toward coal.

Total generation showed both a strong seasonal component, with a peak during July and August, and an increasing trend (Figure 17). Gas-fired generation also exhibited a seasonal pattern. There was a major shift in the SPP region away from natural gas as the primary fuel toward a mix of coal and gas. In addition, nuclear generation increased. Gas-fired generation peaked in 1980, then declined as coal-fired generation increased. Coal-fired generation increased slowly throughout the entire period, from 5 percent of total generation in 1972 to 43 percent in 1982 (Appendix C). Oil-fired generation increased from 4 percent in 1972 to 19 percent in 1978, but had decreased to 1 percent by 1982. Gas-fired generation declined from 88 percent in 1972 to 50 percent of total generation by 1982. Hydroelectric generation, a small component of total generation, showed the typical fluctuations associated with changes in water availability.

Although natural gas costs were lower than both oil and coal costs during the beginning of the period, the natural gas share fell while the oil share increased (Figure 18). Long-term, low-cost gas contracts that were due to expire were a likely factor in the switch from gas. These contracts had allowed the utilities access to natural gas at costs below the market cost.[24] The new contracts would set gas purchases at prevailing market costs and, probably, would include escalator clauses in anticipation of future cost increases. The prevailing gas cost, therefore, did not necessarily reflect expected future costs. Gas curtailments and the threat of long-term gas shortages, together with fuel-use regulations favoring increased coal use, were also probable contributors to the shift away from gas. Following the 1979 cost increase, fuel costs became more important and oil-fired generation was largely phased out. Gas-fired generation was also reduced as coal-fired generation became available, but still remained a major energy source.

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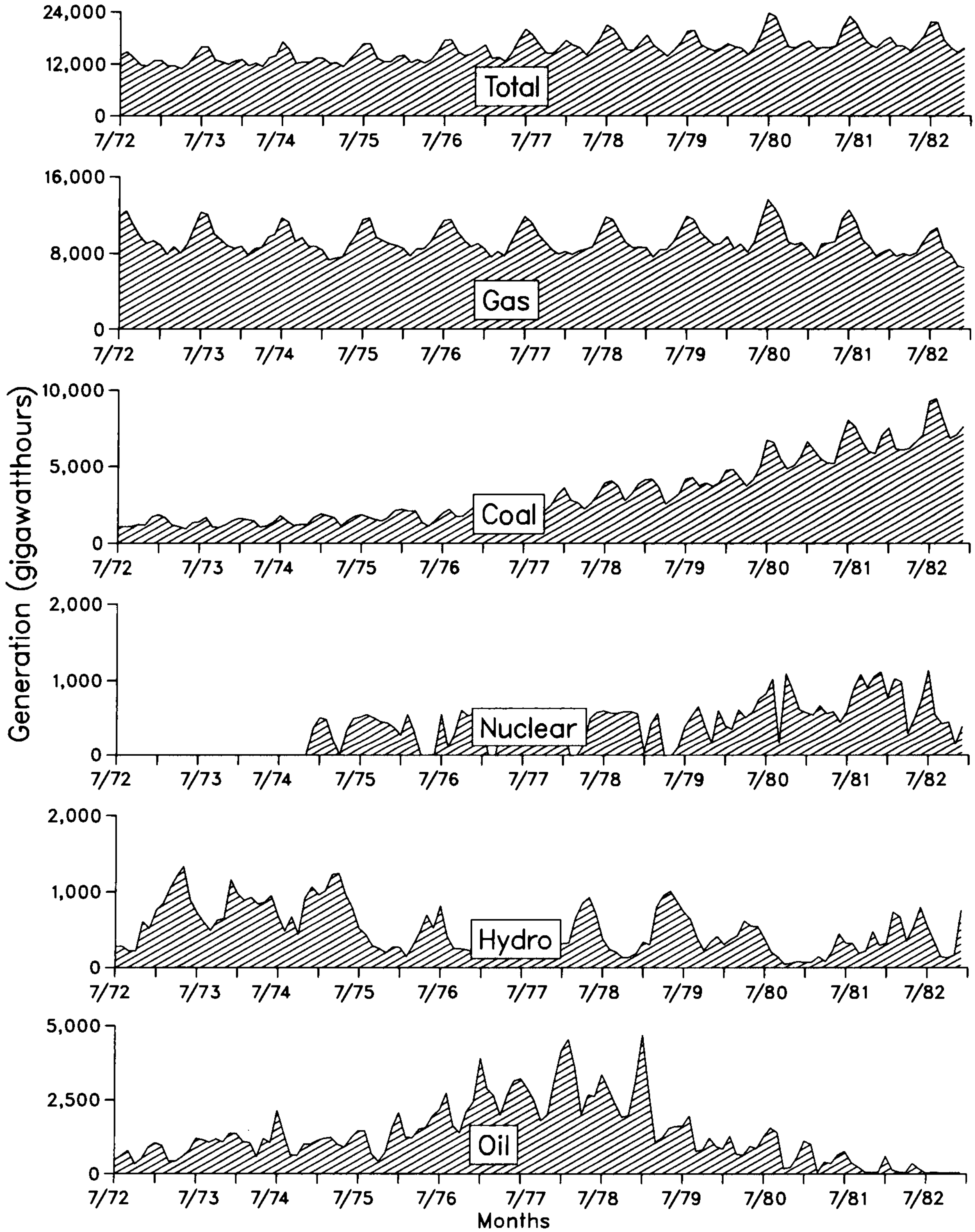
[23]For a general description of SPP, see Federal Energy Regulatory Commission, Power Pooling in the South Central Region, FERC-0053 (Washington, DC, 1981).

[24]The cost was not below the market cost when the contracts were signed. The contracts simply had costs that did not increase when gas costs increased in the early 1970's.

Fuel Choice by Region

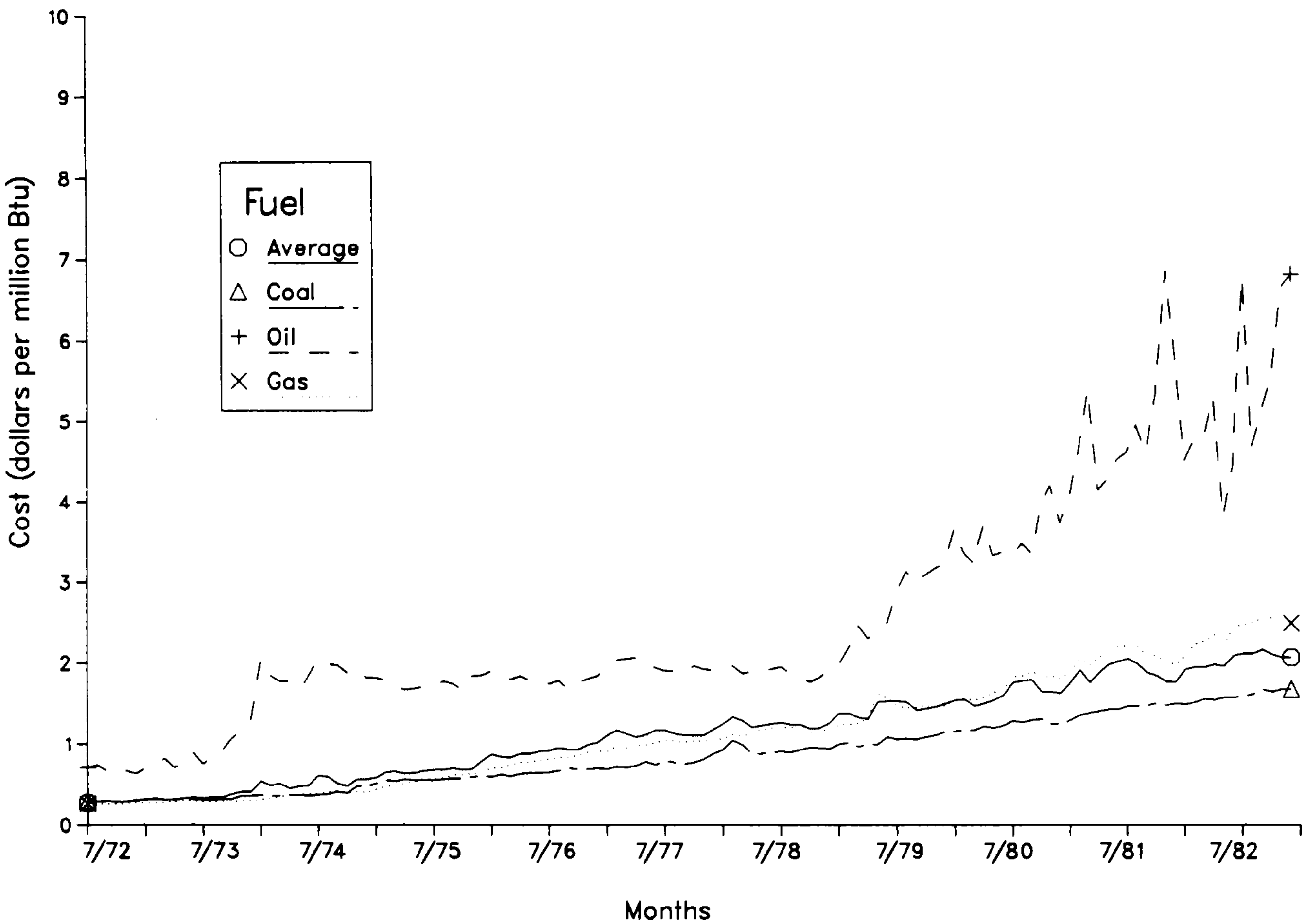
Figure 17. Net Generation by Energy Source in the SPP Region, July 1972-December 1982



Note: Scale for vertical axis differs for each energy source.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Fuel Choice by Region

Figure 18. Fossil-Fuel Costs in the SPP Region, July 1972-December 1982



Note: Average is the quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plant.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuel for Electric Plants," and predecessor forms.

ERCOT

The ERCOT region is electrically isolated from both the Eastern and Western Interconnected Systems, except for direct-current tie lines that are available for emergencies. Three of the largest investor-owned utilities belonged to the Texas Utilities System, a holding-company power pool that provided central dispatch.[25]

Historically, Texas utilities have depended on gas-fired generation, with oil-fired and hydroelectric generation as trivial components of total generation (Figure 19). Since 1973, however, coal-fired generation has become increasingly important. By 1982, coal's share was 39 percent (as compared to 2 percent in 1972), while the natural gas share fell from 96 percent in 1972 to 60 percent by 1982 (Appendix C). However, a major constraint on increasing coal use was the utilization rate of coal-fired capacity, ranging from 69 to 96 percent, in this region (Appendix C). Natural gas thus remained the dominant fuel source with coal as the second most important fuel. Total generation had a strong seasonal pattern (summer-peaking). The increase in coal-fired generation provided for most of the increase in total generation. There were no nuclear power plants in the ERCOT region during the period.

Coal had a definite cost advantage over gas and oil (Figure 20), as in the SPP region. Fuel costs in the ERCOT region, however, show a pattern much different from those in the SPP region. By 1979, natural gas costs were close to oil costs, but subsequently oil costs were well above natural gas costs. Coal costs also increased, but more slowly than gas or oil costs.

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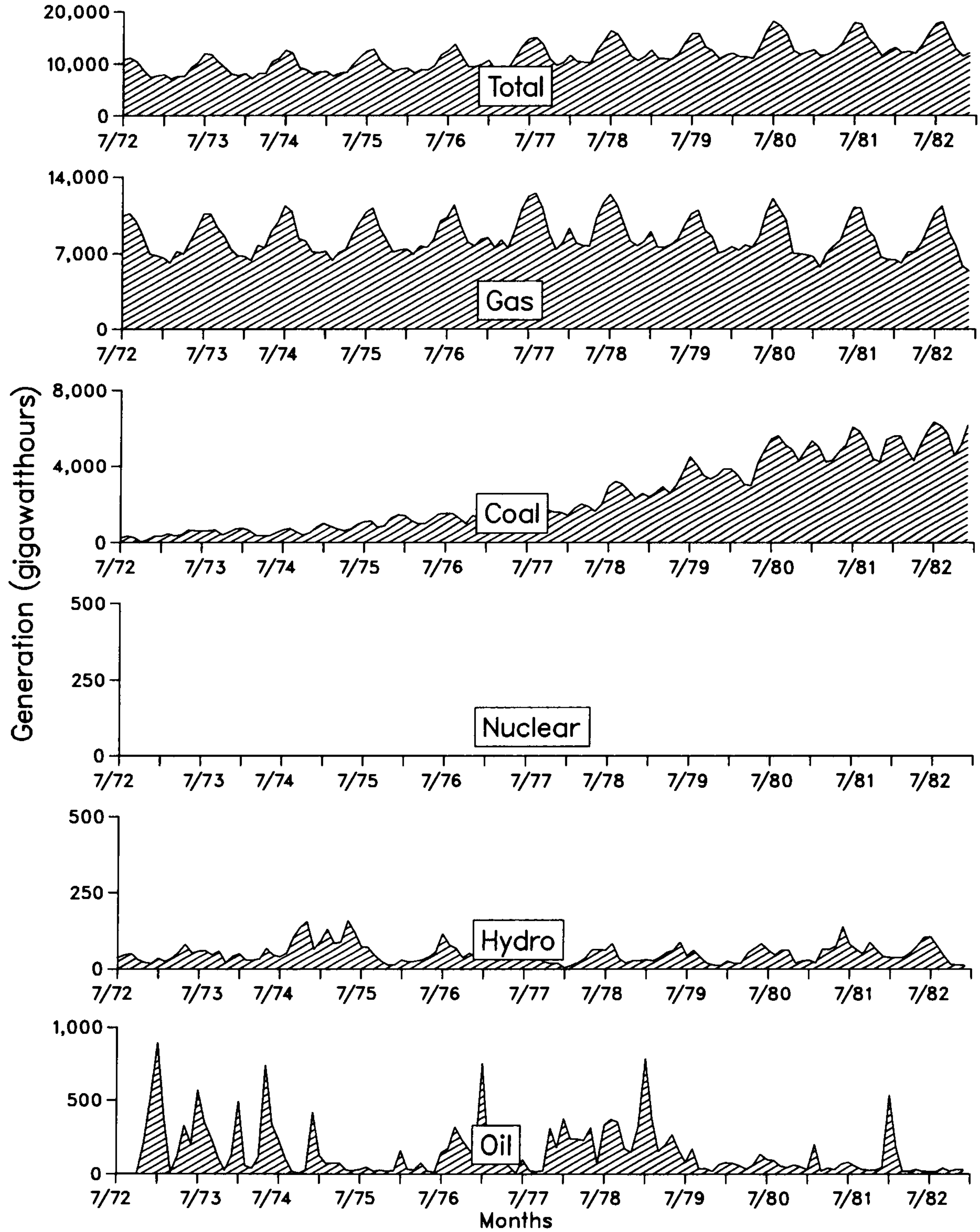
[25]For a general description of ERCOT, see Federal Energy Regulatory Commission, Power Pooling in the South Central Region, FERC-0053 (Washington, DC, 1981). After 1982, the Texas Utility System was reorganized into a single operating utility.

Fuel Choice by Region

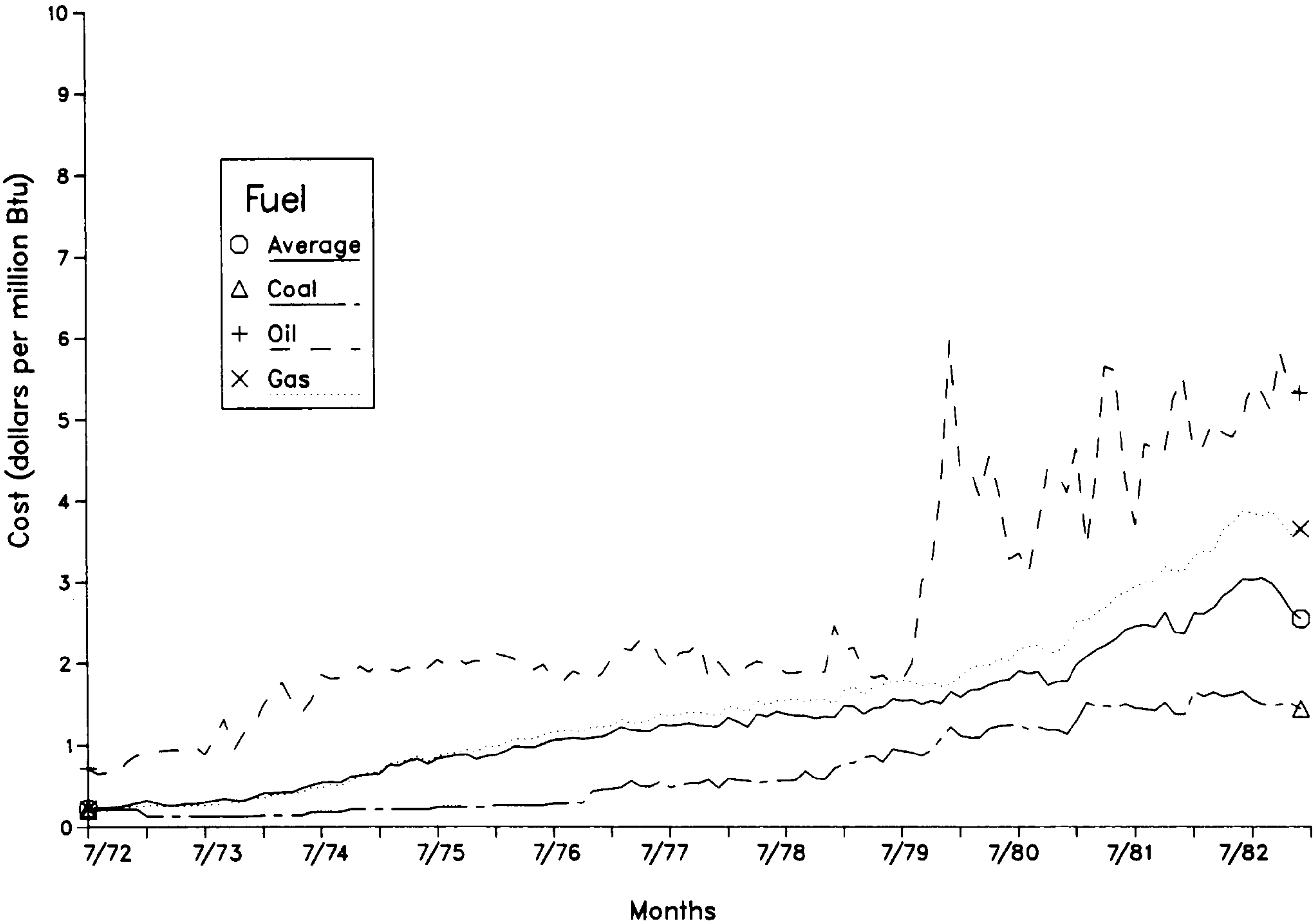
Figure 19. Net Generation by Energy Source in the ERCOT Region, July 1972-December 1982



Note: Scale for vertical axis differs for each energy source.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Fuel Choice by Region

Figure 20. Fossil-Fuel Costs in the ERCOT Region, July 1972-December 1982



Note: Average is the quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plant.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuel for Electric Plants," and predecessor forms.

Fuel Choice by Region

Pacific Northwest

The Pacific Northwest region obtains most of its electricity from hydroelectric generation (Figure 21).[26] Most of the hydroelectric facilities are owned by the Federal Government and operated by the Bonneville Power Administration (BPA). BPA also operates most of the bulk power transmission system in the Northwest Power Pool subregion and coordinates hydroelectric generation and distribution under the Columbia River Treaty.

During the 1970's, utilities in Washington and Oregon built coal-fired power plants to provide additional baseload power because they anticipated that electricity demand growth would exceed dependable hydroelectric resources. Several of these plants are in Wyoming. A major investment was also made in nuclear power plants. Rising construction costs and lower demand growth, however, created problems for several nuclear plants being built by the Washington Public Power Supply System (a consortium of publicly owned utilities), leading to default on interest payments for some of the bonds issued to finance construction. The origins and problems of the Washington Public Power Supply Systems (WPPSS) were beyond the scope of this report. Coal is the dominant energy source in the Rocky Mountain Power Pool subregion.

Coal's share grew while there was a decline in the relative share of hydroelectric generation (Appendix C). However, actual hydroelectic generation increased and accounted for two-thirds of total generation in 1982 in the region. Hydroelectric generation can be threatened by drought; for example, hydroelectric generation fell during the drought of 1977, and coal use increased (Figure 22).

In the 1970's, however, increasing electricity consumption and limited opportunities to expand hydroelectric capacity led to a search for other types of generation to meet forecasted load increases. Given the relative costs of the three fossil fuels (coal, oil, and gas), coal was apparently the most reasonable option.

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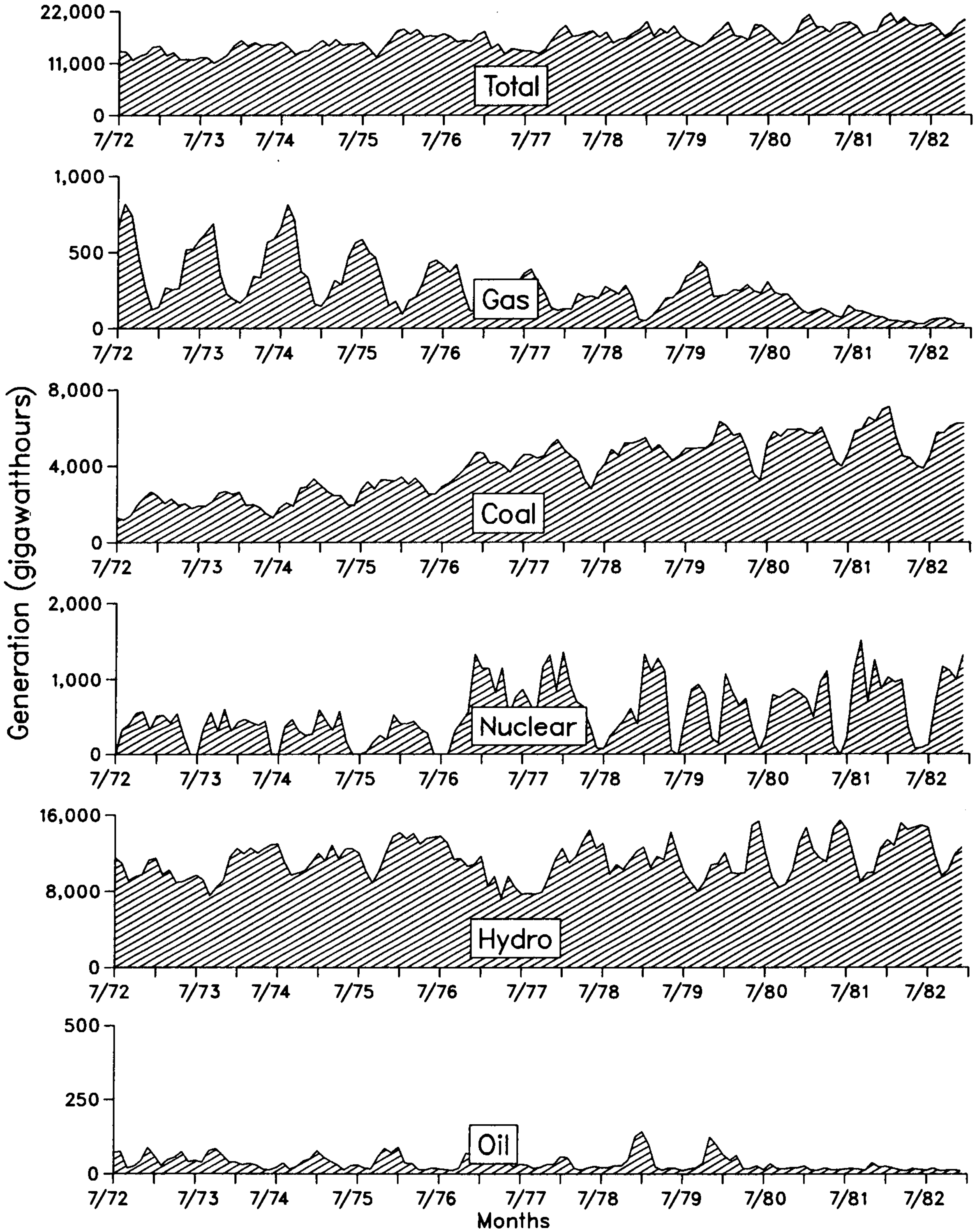
[26] For a general description of the Pacific Northwest region, see Federal Energy Regulatory Commission, Power Pooling in the Western Region, FERC-0053 (Washington, DC, 1981).

Fuel Choice by Region

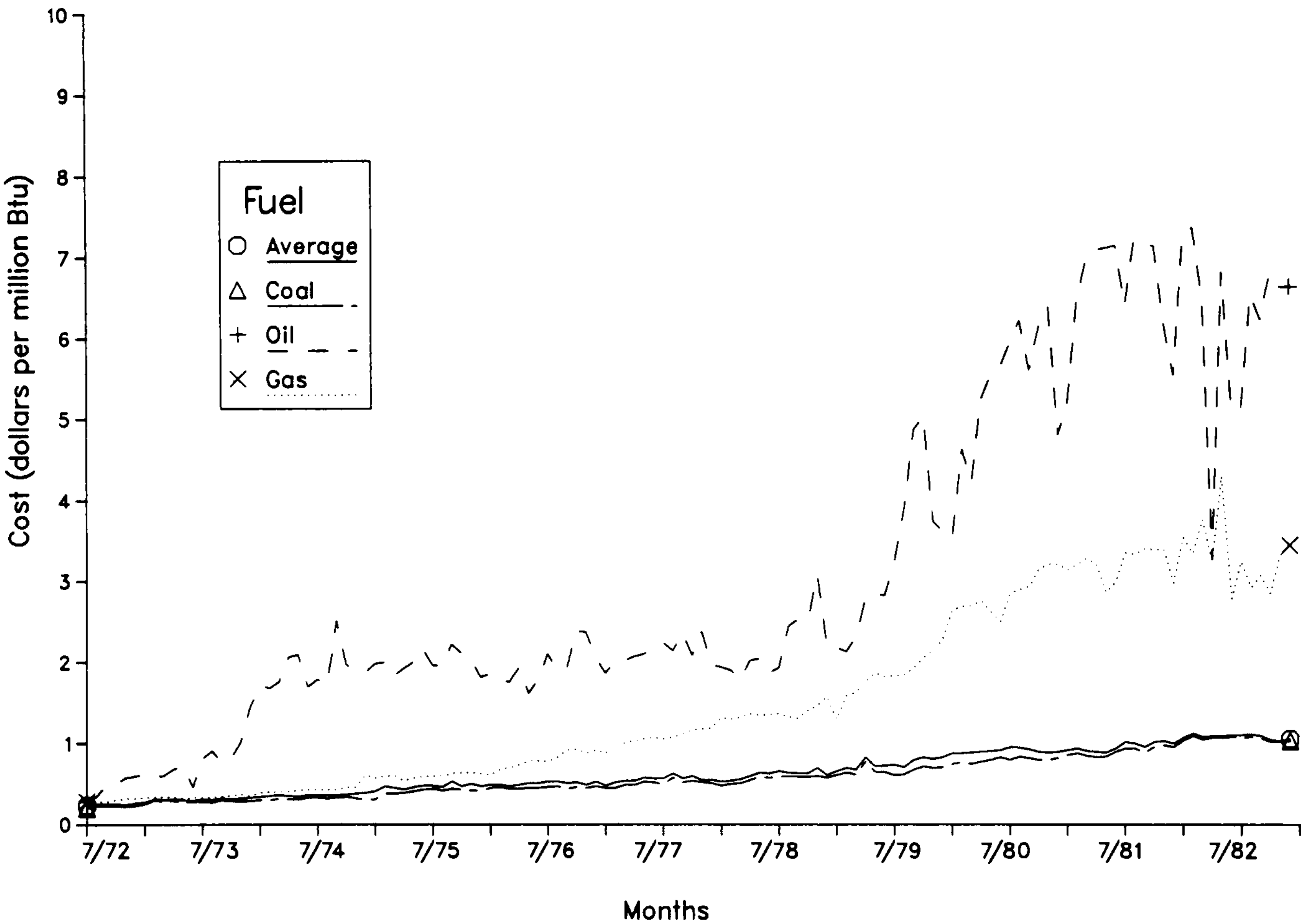
Figure 21. Net Generation by Energy Source in the Pacific Northwest Region, July 1972-December 1982



Note: Scale for vertical axis differs for each energy source.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Fuel Choice by Region

Figure 22. Fossil-Fuel Costs in the Pacific Northwest Region, July 1972–December 1982



Note: Average is the quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plant.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuel for Electric Plants," and predecessor forms.

Fuel Choice by Region

Pacific Southwest

The Southwest region (California, Nevada, Arizona, New Mexico, and the western tip of Texas) has a diverse fuel mix and much experience with fuel switching.[27] Coal-fired, oil-fired, gas-fired, and hydroelectric generation all provided large shares of total generation at some point in the period (Appendix C). Nuclear-powered generation has been a small but important component.[28] At the same time, the use of oil-fired, gas-fired, and hydroelectric generation has fluctuated widely--hydroelectric generation because of erratic rainfall, especially in 1977 (Figure 23). Gas-fired generation fell through the mid-1970's, then increased, while oil-fired generation increased through the mid-1970's, then declined.

Natural gas and oil costs increased sharply after 1979 while coal costs were fairly stable throughout the period (Figure 24). Even so, natural gas continued to provide nearly one-third of total generation. The combination of environmental restrictions and limited transmission capacity probably account for the continued use of natural gas in spite of the overwhelming cost advantage of coal.

California (the largest user of electricity in the region) has, for all intents and purposes, prohibited the construction of coal-fired power plants in the State. All coal-fired generation for the region is from power plants that are located in other States, although in many cases these plants are owned entirely or in part by California utilities. California consumes a large share of this coal-fired generation, which must be transmitted over a power grid that also carries power from Hoover Dam and purchased power from Utah and Colorado. California also receives significant hydroelectric power transfers from the Northwest region.

The entire transmission system in the WSCC (which was divided into the Northwest and Southwest for this report) has, in recent years, been utilized at close to maximum reliable capacity.[29] By 1982, transmission of coal-generated electricity from Nevada, Arizona, and New Mexico (and even more so, imports of hydroelectric power from the Pacific Northwest) had stretched the regional transmission system to its safe operating limits. There was simply no more capacity available during high demand periods.

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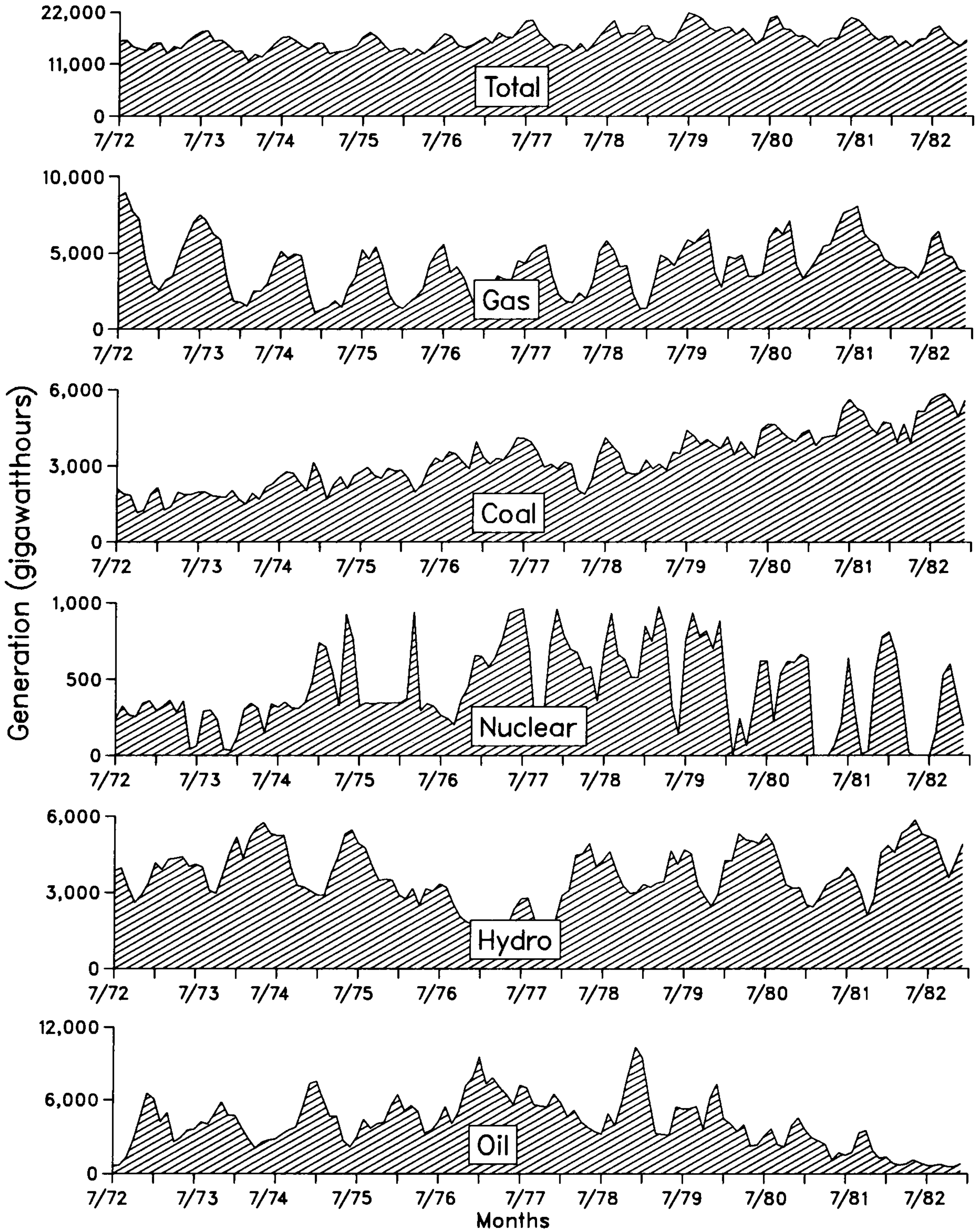
[27] For a general description of the Pacific Southwest region, see Federal Energy Regulatory Commission, Power Pooling in the Western Region, FERC-0053 (Washington, DC, 1981).

[28] The Southwest is the one region where "other" generation (in this case geothermal steam) has been important.

[29] North American Electric Reliability Council, 1982 Annual Report (Princeton, New Jersey), p. 47. Unscheduled power flows ("loop flows") are a recurring problem that reduces transmission system capacity for scheduled power transfers.

Fuel Choice by Region

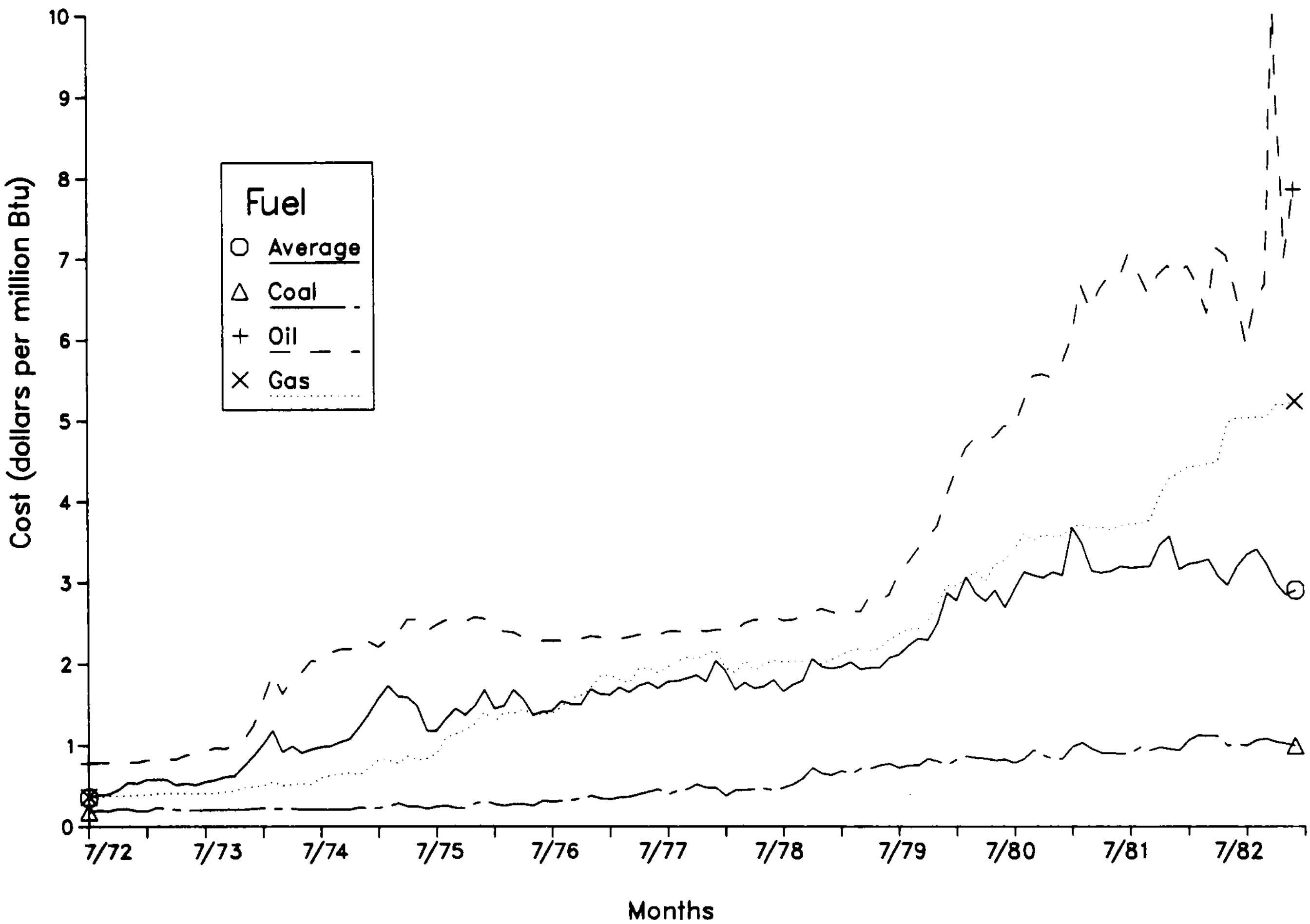
Figure 23. Net Generation by Energy Source in the Pacific Southwest Region, July 1972-December 1982



Note: Scale for vertical axis differs for each energy source.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

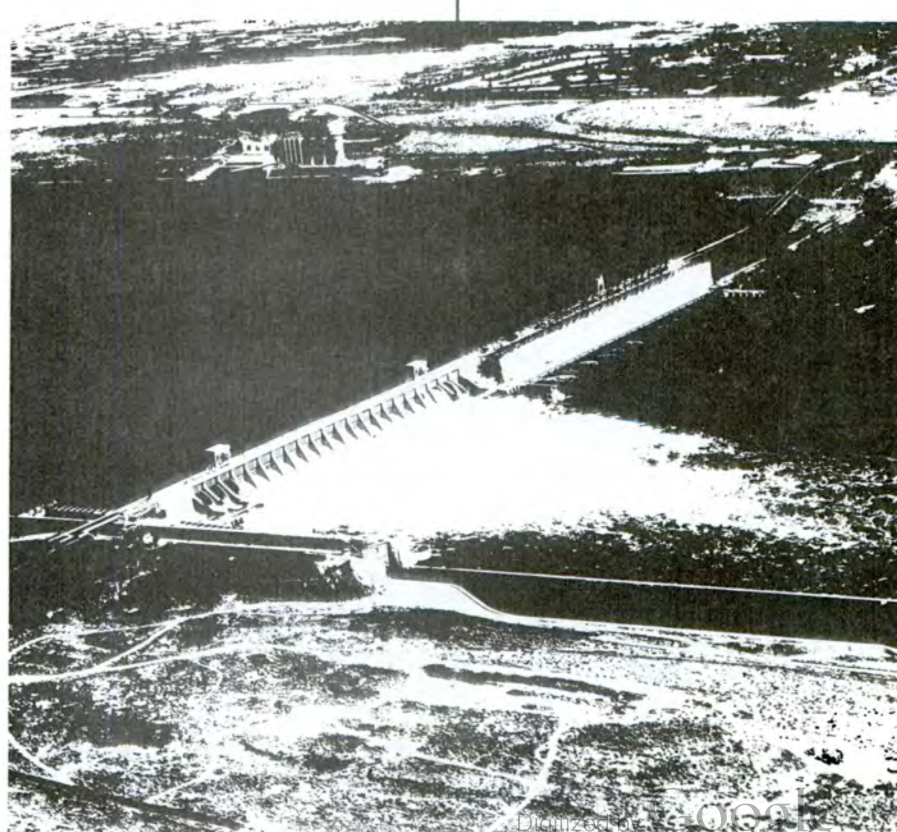
Fuel Choice by Region

Figure 24. Fossil-Fuel Costs in the Pacific Southwest Region, July 1972-December 1982



Note: Average is the quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plant.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuel for Electric Plants," and predecessor forms.

Summary



5. Summary

Influence of Fossil-Fuel Costs on Fuel Choice

Oil costs were likely one of the principal reasons for the reduction in oil-fired generation during the 1970's and early 1980's. However, from July 1972 through December 1978, oil-fired generation changed very little in most regions as compared to the period from January 1979 through December 1982. This suggests that the 1973-1974 oil cost increase had less effect on oil-fired generation than the 1979-1980 cost increase. There are two possible explanations.

First, the earlier cost increase was probably not large enough to affect demand substantially, whereas the 1979-1980 cost increase (on top of the earlier increase) was. Second, options for responding to increased oil costs were more limited prior to 1979. Between mid-1972 and the end of 1978, natural gas supplies were curtailed and further reductions were expected. In addition, replacing oil with coal or nuclear energy required large-scale construction projects which take years to complete. Environmental concerns had also limited the extent to which utilities could build new coal-fired plants. By 1979, however, concern over natural gas supplies had diminished, and utilities were able to substitute gas for oil in steam generation in many regions. Also, additional coal-fired and nuclear power plants ordered earlier began to come on line. In all regions, utilities apparently responded to the 1979 cost increase by reducing oil-fired generation and increasing gas-fired generation, at least in the short run. A few regions were able to displace oil by using coal-fired or nuclear generation produced in other regions.

From July 1972 through December 1982 in those regions that were using coal as the primary energy source, coal-fired generation increased as coal costs rose. In the SPP and ERCOT regions gas-fired generation declined as gas costs increased. These two regions used natural gas as the primary baseload fuel more heavily than did other regions and are more likely to reflect economic decisions based on cost minimization than other regions.

Influence of Environmental and Fuel-Use Regulation on Fuel Choice

The continued baseload use of gas- or oil-fired generation in the New England, New York, MAAC, Florida, and Pacific Southwest regions may have been due to environmental regulations restricting switching to coal in these regions. This, however, is not the only explanation. New England, Florida, and California (the largest electricity producing and consumer State in the Pacific Southwest region) lack indigenous coal supplies and are far enough from coal-producing areas to make transportation costs a serious factor. In New England and Florida the difference between coal and natural gas costs was probably not large enough over most of the period to compensate for the higher costs of coal-fired power plants. In addition, in all of these regions, transmission system limits prevented utilities that depend on oil- or gas-fired generation from importing enough power from coal-fired power plants into their load centers.

Still, environmental restrictions are a factor. There are no coal-fired power plants in California, although California utilities have invested in such power plants in Nevada, Arizona, New Mexico, and Utah. In the 1970's, coal-fired power plants in Florida and MAAC (and elsewhere) were converted to oil for environmental reasons. Some of these plants were or are now being converted back to coal. Much of the generating capacity in the New York City area is officially designated as coal capable (which means that there are facilities to use coal in the existing boilers), but no coal has been used in this capacity since the early 1970's.

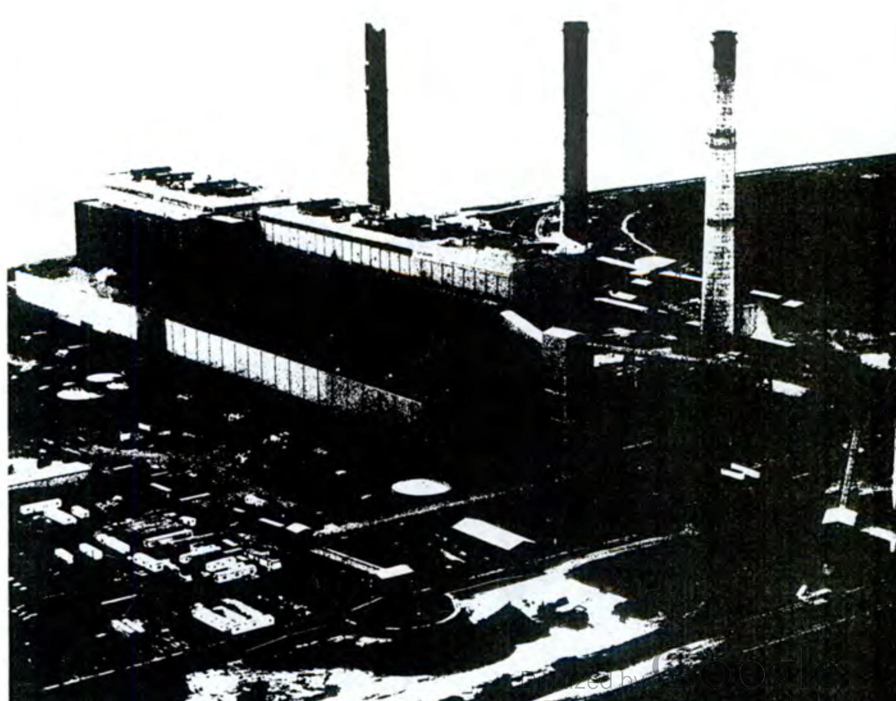
Implications for Fuel Choice in the Future

While this report does not forecast future trends in fuel choice, it is worthwhile to consider what the implications for the future may be. Changes in fuel costs will probably play an important role in future fuel-switching decisions. Any major change in relative fuel costs from current conditions will likely cause the electric utility industry to change its fuel use in the direction of the lower cost fuel. Any such changes will be constrained in the short run by regulatory factors and by the fuel capabilities of existing generating capacity.

The utilities that are using oil recognize both the high costs and vulnerability of this fuel. They have responded to the situation by (1) planning construction of additional coal-fired and nuclear generating capacity, (2) strengthening the transmission system, and (3) seeking energy from other utilities, including utilities in Canada. However, there are a number of constraints on their ability to replace oil capacity. A combination of high interest rates, inflation in construction costs, regulations, financial constraints, and mismanagement of certain construction projects have substantially slowed the building of new generating capacity. Technical, financial, and regulatory factors have also slowed expansion of the transmission system. There are also potential constraints that are caused by utility preferences for expanding their own generating capacity, rather than using additional purchased power. These constraints include: economic incentives for expanding the rate base instead of finding lower cost supply sources (especially purchased power); competition among utilities for industrial and requirements customers (municipal and cooperative utilities); and existing marketing arrangements that increase the costs of third party transmission (the cost charged by a utility for transmitting power between two other utilities). This list of constraints touches on virtually all aspects of electric utility planning and operations, and even so is not exhaustive. These issues are beyond the scope of this report.

Appendix A

Federal Environmental and Fuel-Use Legislation



Appendix A

This appendix describes major Federal environmental and fuel-use legislation most commonly recognized as affecting electric utilities:

- The National Environmental Policy Act
- The Clean Air Act
- The Federal Water Pollution Control Act (Clean Water Act)
- The Resource Conservation and Recovery Act
- The Energy Supply and Environmental Coordination Act
- The Powerplant and Industrial Fuel Use Act
- The Omnibus Budget Reconciliation Act.

Environmental Legislation

The National Environmental Policy Act

The National Environmental Policy Act of 1969 (NEPA, P.L. 91-190) explicitly sets protection and improvement of the environment as national policy and establishes certain Federal responsibilities in pursuit of that policy.

Under NEPA, Federal agencies must disclose fully the environmental consequences of all major Federal actions significantly affecting the environment by preparing an Environmental Impact Statement (EIS). The EIS must describe the environmental impacts, unavoidable adverse consequences, alternatives, and any long-term or irreversible effects of proposed Federal actions. EIS's are subject to review and comment by the public and other Federal, State, and local government bodies prior to approval. Electric utility power plant construction or modification typically requires at least one major Federal action via a license or permit, which involves preparing and defending an EIS.

The Clean Air Act

Clean air legislation of the 1970's consisted chiefly of the two basic Acts, the Clean Air Act of 1970 (CAA, P.L. 91-604) and the Clean Air Act Amendments of 1977 (P.L. 95-95). With respect to electric utilities, CAA principally directs the Environmental Protection Agency (EPA) to set nationwide standards for acceptable levels of sulfur dioxide (SO_2) emissions, and strengthens the Federal role in enforcing these standards. Standards are also set for acceptable levels of nitrogen oxide (NO_x) and particulate emissions. The Act principally affects the SO_2 emissions of coal-fired units.

In 1971 EPA issued National Ambient Air Quality Control Standards (NAAQCS): primary standards based on health tolerances and secondary standards based on public welfare considerations (property damage, vegetation effects, and scenic

Appendix A

values). Standards are formulated in terms of ambient (surrounding) air concentrations of specified pollutants.

These standards apply to 247 U.S. Air Quality Control Regions for each pollutant. Each region is designated either an "attainment area," with respect to a pollutant standard if the standard is met, or a "nonattainment area" if the standard is not met. State Implementation Plans (SIP's), to be developed and enforced by each State, contain individual State attainment strategies. By and large, State-established SIP requirements apply to pollution control measures affecting existing facilities in nonattainment areas.

Under "New Source Performance Standards" (NSPS) set by the EPA in 1971, all new or modified power plants with a capacity of 73 or more megawatts may emit an annual average of no more than 1.2 pounds of SO2 per million British thermal units (MMBtu). NSPS annual average emission limits for nitrogen are 0.7 pounds of NOx per MMBtu and for particulates, 0.1 pounds per MMBtu.

In 1977, the Clean Air Act was amended to require that States set limits on existing pollution sources within nonattainment areas by use of "reasonably available pollution control technologies" (RACT). Both economic and technological feasibility may be considered in determining RACT. Existing power plants in attainment areas remain unaffected under both the 1970 Act and its amendments. Existing power plants in attainment areas remain unaffected by the Clean Air Act, while existing power plants in nonattainment areas follow RACT under its 1977 amendments.

Revised New Source Performance Standards (RNSPS) for power plants, new or modified after 1978, were issued in 1979. RNSPS introduces a sliding scale of emissions controls that ranges from permitted emissions of no more than 1.2 pounds of SO2 per MMBtu and reducing SO2 emissions by at least 90 percent, to emissions of no more than 0.6 pounds but requiring a reduction of no more than 70 percent. These ranges effectively requires the use of flue gas desulfurization (FGD) equipment.

<u>The Federal Water Pollution Control Act of 1972 (The Clean Water Act)</u>

The Federal Water Pollution Control Act of 1972 (P.L. 92-500), better known as the Clean Water Act, prohibits any discharge into public waterways unless authorized by permit. The discharge permit program, titled the National Pollutant Discharge Elimination System (NPDES), limits the quantity of each pollutant that may be discharged by either existing or new dischargers. For the electric utility industry, the standards cover:

1. Thermal pollution from utilities' cooling systems;

2. Metal-cleaning wastes, site-water runoff, total suspended solids (TSS), oil and grease, and copper and iron in waste streams;

3. Ash transport water wastes (sludge) containing TSS, oil, grease and trace elements; and

Appendix A

4. Chemical discharges, particularly chlorine, zinc, chromium, and polychlorinate biphenyls (PCB's).

Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act of 1976 (RCRA, P.L. 94-580) establishes standards for the handling of solid waste products. RCRA distinguishes hazardous from nonhazardous wastes. For the former, EPA sets standards requiring (1) "cradle-to-grave" monitoring of the origins, types and quantities of wastes, their transportation and disposal, and (2) issuance of permits for hazardous waste disposal sites. Rules for disposal of nonhazardous wastes are set by the individual States.

Electric utilities typically dispose of only small volumes of hazardous wastes: chemical wastes from metals-cleaning processes and from degreasing, and from chemicals in transformers and other electrical equipment. Utilities generally ship these wastes to other disposal sites, they do not maintain sites themselves. Nevertheless, all utilities face the added costs of documentation, transportation, and disposal at more expensive approved locations.

Fuel Choice Legislation

Energy Supply and Environmental Coordination Act

The Energy Supply and Environmental Coordination Act of 1974 (ESECA, P.L. 93-319) promotes greater use of coal in the place of petroleum and natural gas. ESECA directs the Federal Energy Administration (FEA, later DOE) to identify and prohibit specific existing power plants from using petroleum or natural gas if DOE determines that:

1. The power plant has coal-burning capability;

2. Coal burning is practical and consistent with U.S. fuel needs and environmental requirements;

3. Coal and coal transportation facilities are available; and

4. Electric service reliability will not be impaired.

Further, under ESECA, DOE may require that any new power plant in the early planning process be designed and constructed to use coal as its primary energy source, so long as reliability and adequacy are not impaired.

Powerplant and Industrial Fuel Use Act

The Powerplant and Industrial Fuel Use Act of 1978 (FUA, P.L. 95-620) extends and increases Federal involvement in electric utilities' fuels choice in two particularly significant ways:

Appendix A

1. FUA establishes blanket prohibitions applicable to all power plants meeting specified characteristics; thus the onus of specific discovery and prohibition is removed from the Federal Government and placed on utilities.

2. FUA expands the consideration of alternate fuels from coal alone to "coal or other alternate fuels."

FUA establishes prohibition and exemption criteria separately for new power plants and for existing power plants. The prohibitions for new power plants are:

1. Natural gas or petroleum shall not be used as a primary energy source.

2. Any new electric power plant constructed must be capable of using coal or another alternate fuel as a primary energy source.

The prohibitions for existing power plants are:

1. Natural gas shall not be used as a primary energy source in existing electric power plants on or after January 1, 1990. Natural gas shall not be used as a primary energy source in existing power plants before January 1, 1990, unless such power plants used natural gas as a primary energy source at any time during 1977, but not in greater proportions. Note that the prohibitions apply only to existing plants that burn natural gas and not to those that burn petroleum.

2. The Secretary may prohibit the use of petroleum or natural gas as a primary energy source in any existing electric power plant if the power plant has or had the technical capability to use coal or another alternate fuel as a primary energy source.

Prohibition orders under ESECA remain in force under FUA; however, authority of the Secretary to issue new orders under ESECA terminated with FUA.

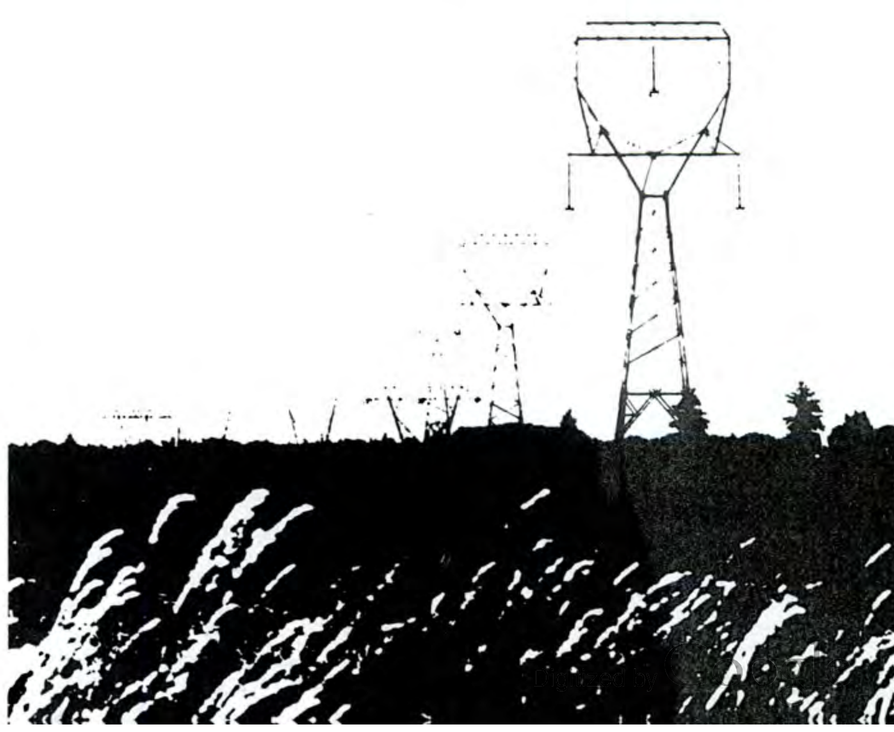
The Omnibus Budget Reconciliation Act of 1981

The Omnibus and Budget and Reconcilation Act of 1981 (OBRA, P.L. 97-35) reflects changing Federal emphasis away from regulatory influences and toward reliance upon market forces.

OBRA amended FUA by removing prohibitions against the use of natural gas in existing electric power plants. It removed blanket prohibitions barring use of natural gas as a primary energy source by existing power plants after January 1, 1990, and prohibitions against using increased proportions of natural gas. Further, OBRA reverses the prohibition procedure from one in which involuntary prohibitions might occur to one in which only voluntary prohibitions can occur. Under OBRA, the owner or operator of a power plant may certify to DOE that the plant can use coal or another alternate fuel as a primary energy source. Only upon such self-certification and DOE concurrence may the Secretary prohibit use of natural gas in increased proportions.

Appendix B

Constraints on Fuel Choice



Appendix B

This appendix discusses constraints on short-term fuel choice associated with the operation of boilers capable of burning more than one fossil fuel and the transfer of electric power through high-voltage transmission systems.[1]

Boiler Constraints

Background

Each of the boiler constraints considered is evaluated on the basis of sequential firing of the primary and alternate fuels and on the type of fuel-switching involved. With sequential firing, the boiler can burn only one fossil fuel at a time.[2] The seven constraints considered are listed in order of importance.

- Capital costs
- Derating
- Availability of fuel
- Reduced efficiency
- Operating problems
- Reduced availability
- Increased operating personnel.

There are three basic fossil fuels: natural gas (referred to hereafter simply as gas), oil, and coal. A review of the boilers with alternate fuel capability shows that only the primary and secondary fuel combinations listed in Table B1 are used currently.

Capital Costs

The capital cost constraint does not apply to boilers that require major modifications to operate with the alternate fuel capability. Major modifications are considered to be modifications to the boiler heat transfer surfaces, reconstruction of the burners, new boiler bottoms, and new air preheaters.

Boilers that burn fuel oil only on an emergency basis usually have oil storage in day tanks with a capacity of 2 or 3 days fuel. However, on a long-term basis, 30 to 60 days of storage would be required at a cost of several million dollars for the installation of the tanks. The same problem can exist with boilers that burn coal as an alternate fuel. Some boilers have facilities that allow only one or two coal cars to be dumped per hour into a conveying system that brings coal directly to a boiler. Under these conditions, coal combustion would be on an

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[1]The discussion of constraints associated with boilers burning more than one fuel is based primarily on work done by PEDCo Environmental, Inc., under contract No. DE-ACOI-84EP12067, Task 8A.

[2]Some boilers have alternate fuel capability based on concurrent firing of the primary and alternate fuels, that is, the boiler can burn more than one fossil fuel simultaneously. This type of capability is not discussed in this appendix.

Appendix B

Table B1. Possible Fuel Combinations

Primary Fuel[a]	Possible Secondary Fuel
Natural gas (gas)	No. 2 oil, No. 4 oil
No. 2 oil	Gas, No. 4 oil
No. 4 oil	Gas, No. 5 oil
No. 5 oil	Gas, No. 6 low-sulfur oil
No. 6 low-sulfur oil	Gas, Coal
No. 6 high-sulfur oil	Gas, Coal
Coal	Gas, No. 6 low-sulfur oil, No. 6 high-sulfur oil

[a]No. 2 fuel oil: a distillate fuel oil for use in atomizing-type burners for domestic heating, or for moderate-capacity commercial/industrial burner units.

No. 4 fuel oil: a fuel oil for commercial burner installations not equipped with preheating facilities. This grade is a blend of distillate fuel oil and residual fuel oil stocks.

No. 5 fuel oil: residual fuel oil of intermediate viscosity for burners capable of handling a product more viscous than grade No. 4 distillate fuel without preheating in milder climates.

No. 6 fuel oil: a high-viscosity fuel oil for commercial and industrial heating and power generation. Preheating is required for satisfactory use.

Natural gas: a mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in underground reservoirs.

Coal: a generic term applied to carbonaceous rocks formed by the partial or complete decomposition of vegetation. These stratified carbonaceous rocks are solid, brittle, and highly combustible. Includes lignite, bituminous coal, and anthracite.

Source: PEDCo Environmental Inc., "Evaluation of the Engineering Constraints on Fuel Switching at Multi-Fueled Utility Boilers" (November 1984), p. 6.

emergency basis only. To burn coal over a long period of time automatic coal-handling equipment would be needed, at a cost of $55-$75 per kilowatt (1984 dollars).

Derating

Derating a unit (reducing a boiler's steam capacity from its design capacity) is one of the most significant operating constraints on a utility. Utility systems depend on the capability of each unit to generate a given quantity of electricity, thus derating a unit would alter the overall operation of the system.

Appendix B

Figure B1 shows the relative size for coal-, oil-, and gas-fired furnaces for the same steam capacity rating. Furnaces designed only for oil firing are slightly smaller than coal-fired units, and somewhat larger than gas-fired units. The primary design consideration for oil- and coal-fired units is protecting tube wall integrity, because oil and coal cause a higher luminosity flame than gas, and consequently transfer more heat to the furnace walls.

Boiler derating is caused by the size of the boiler combustion chamber and soot and slag buildups on heat-transfer surfaces. Derating is generally not a problem except for gas-fired boilers being switched to fuel oil No. 4 and for oil-fired boilers using fuel oil No. 6 being switched to coal. A more complete discussion follows.

A steam generator designed to fire only gas is a relatively compact low-cost unit. Because gas is clean and easy to burn, the volume of a natural gas furnace needs to be only large enough to ensure complete combustion. Gas firing radiates less heat to the furnace walls because its flame is relatively nonluminous.

The problems associated with ash in other fuels are not a concern in the design of a gas-fired furnace. The superheater and reheater tubes can be placed close together to gain maximum heat transfer. Since the very low-sulfur content of gas does not lead to low-temperature acid corrosion, air heaters can be compact and designed for low-exit gas temperatures.

Fuel oil No. 2 is a non-ash-bearing clean fuel. Therefore, the design of a boiler to fire fuel oil No. 2 exclusively would be similar to that of a natural gas boiler with optimization of combustion and heat transfer.

Oil firing is a rapid combustion process with intense heat radiation from highly luminous combustion gases. Therefore, there is a very high and localized heat absorption rate within the active burning zone of the furnace. To control these high absorption rates, the furnace size must be increased above the minimum required for complete combustion only.

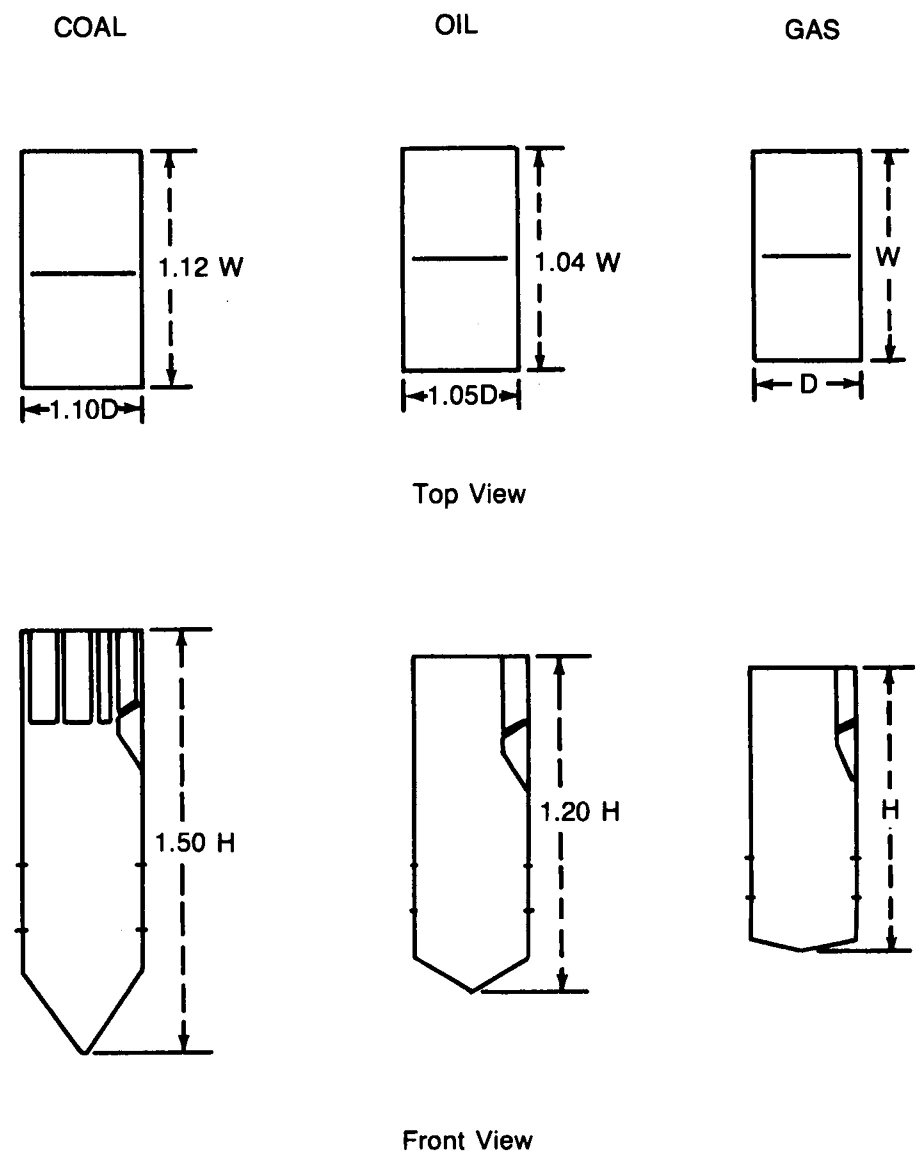
Residual oils (Nos. 4, 5, and 6) and crude oils contain ash and other impurities that require special design considerations for the boiler. The superheater and/or reheater tubes must be placed far enough apart to prevent fouling in the gas passage lanes. Soot blowers are required to remove any accumulation of deposit on these tubes.

Coal-fired boilers must be much larger than boilers designed to burn gas because they burn more slowly and need more air for firing. Also, coal's higher ash content requires that the convection pass tube spacing be much wider and the flue gas velocities be much lower in order to prevent excessive erosion of the tubes.

Units burning low-sulfur subbituminous coals or lignite require special design considerations for the boiler. The reduced heating value and higher moisture content for subbituminous coal and lignite compared to bituminous coal mean that more fuel must be burned to achieve a given capacity rating, thus requiring larger units. Low-sulfur fuels frequently have a higher potassium content. Potassium can cause high-temperature corrosion, requiring unique construction materials or the addition of other chemicals to the fuels to reduce corrosion. Units firing subbituminous coal must have special widely spaced panels and platens (flat plates

Appendix B

Figure B1. Relative Size of Typical Furnaces by Fuel Type for the Same Steam Capacity



Note: W = Width, D = Depth, and H = Height.
Source: PEDCo Environmental, Inc., "Evaluation of the Engineering Constraints on Fuel Switching at Multi-Fueled Utility Boilers," (Arlington, Texas, November 1984), p. 10.

Appendix B

used for heat transfer) in the upper furnace area to cool the gases until their temperatures are below that of ash fusion before they enter the more closely spaced convection areas.

As different fuels are burned in the same boiler, the amount of heat absorbed changes in order to maintain the required combustion parameters. The three boilers shown in Figure B1 are designed to generate the same amount of steam given the three different fuels. Therefore, assuming a constant furnace size, the amount of steam that could be generated from these fuels is 100 percent for gas, 75 percent for oil, and 54 percent for coal.

Availability of Fuel

There are three constraints on fuel availability: fuel type, storage capacity, and delivery capacity. Fuel type is an constraint because of vulnerability of the fuel to curtailment or embargo. Delivery capacity is site-specific and is evaluated for each individual boiler.

Coal is the most dependable fuel because large domestic supplies are available. In times of national emergency, coal is not likely to be curtailed. Coal can be transported readily by rail, truck, barge, and conveyor belt, and usually a 60- or 90-day supply can be stored at the plant site.

Supplies of oil are less reliable than those of coal. Even though there are large domestic reserves, a significant amount of oil used in utility boilers is imported and therefore is subject to embargo. Oil is relatively easy to transport and storage capacity exists at refineries, terminals, and most power plants.

Gas as a utility fuel is limited both by supply and legislation. In the 1970's the limited supply of gas and its primary use in home heating made its use as a utility fuel subject to curtailment. Gas is not easily stored; it enters the pipeline system at the wellhead and does not go into any storage system except the storage capacity of the pipeline system itself.

In many cases, a plant may not have adequate fuel storage capacity or a fuel may be unavailable when switching is needed. For example, fuel switches by a utility to gas during the winter months are frequently restricted by the higher priority assigned to meet residential demand. Also, alternate fuels are not usually stored on-site in large quantities; therefore, switching to alternate fuels may be very slow.

Reduced Efficiency

Boiler efficiency is a function of the amount of net heat extracted from the fuel during the combustion process. Boilers extract heat in three major areas: the combustion chamber, the upper furnace gas passages, and the air preheater.

The major combustion properties of each fuel type that are of concern are the luminosity of the combustion gases, the rate of burn, the ash properties, the ash content, the moisture content of the fuel, the moisture content of the products of combustion, the condensation temperature of the flue gases, and the excess air requirements of the fuel.

For a given furnace design, the combustion properties of each fuel type change the ability of the furnace to remove heat. For example, a highly luminous, rapidly burning fuel (like oil or coal) makes the walls of the combustion chamber much hotter than would gas. Therefore, to prevent the furnace walls from overheating, the amount of oil or coal burned in a given furnace volume must be less than the amount of gas that could be burned. As less heat is taken out of the furnace combustion chamber, more heat must be taken out in the upper furnace gas passages. This alters the original design's provision for the extraction of heat, and reduces the system's thermal efficiency.

If the ash content of the secondary fuel is higher than that of the primary fuel, then ash will accumulate more quickly on heat-transfer surfaces, which requires more frequent soot blowing to keep the heat-transfer surface clean and operating efficiently. High fuel moisture or higher hydrogen content in the fuel causes higher moisture in the flue gases and reduces efficiency because latent heat losses are increased. Generally, switching to an alternate fuel will reduce a boiler's efficiency, since its design parameters cannot be optimized for both fuels.

Operating Problems

Operating problems are divided into the following areas:

- Fuel storage
- Pollution control
- Unit stability
- Ash handling
- Soot blowing
- Control systems, that is, flow sensors, oxygen controls, and system response
- Heat transfer surfaces.

Fuel Storage. Fuel storage problems are unique to the type of fuel being used. For example, utilities do not normally store natural gas, but oil is stored even though it has some fuel storage problems. Fuel oils No. 2, No. 4, and No. 5 generally are fluid enough that they do not require heated storage; however they can become quite viscous and difficult to pump at very low ambient temperatures. Fuel oil No. 6, which is heavy and viscous, must be kept hot, both in storage and in use. If a utility is burning fuel oil No. 6 and maintaining it in storage without the intention of having it immediately available as a fuel, then heating the storage tank may not be necessary. However, the heat-up time for very large storage tanks can be several weeks. Most utilities would not maintain a stock of oil as an auxiliary fuel unless they were able to burn it in a matter of a few hours.

Another problem associated with fuel storage tanks is the accumulation of water. Although storage tanks have provisions for periodic removal of water, the presence of water causes long-term corrosion damage to the tanks and problems at the burner tips. Tank corrosion also arises from the oils themselves, since most oils are

Appendix B

somewhat corrosive. Periodic inspections of the tanks are required. These inspections are costly, since a thorough tank inspection requires draining the tank to allow visual inspection of its interior.

Coal has some unique storage problems. Coal must be properly compacted during storage to prevent excessive weathering and coal pile fires caused by spontaneous combustion. Also the conveying equipment necessary to move the coal from the storage pile to the boiler requires periodic maintenance, and for proper use, it must be operated periodically.

Pollution Control. The most common pollution control devices used on multifuel utility boilers are electrostatic precipitators. They generally operate without any particular problems when the utilities switch to the alternate fuels.

Fabric filters or "bags", which are quite effective for particulate control on coal-fired boilers, tend not to be usable on oil-fired boilers because of the oily residue that results from combustion. The residue accumulates on the fabric and eventually blinds or plugs the bags, making them unusable. Therefore, whenever oil is an alternate fuel at a facility equipped with a fabric filter, the filter is bypassed when the unit is operating on oil, in order to prevent permanent damage to the bags. Approximately 4 percent of coal-fired boilers that can burn oil as an alternate fuel are equipped with fabric filters. Gas as an alternate fuel generally does not create any serious problems associated with the operation of fabric filters.

Unit Stability. A unit that uses coal as a primary fuel with oil as an alternate fuel would have to use extreme caution when beginning operation with oil in order to ensure proper stabilization of the oil burn. Operation of a boiler with coal as an alternate fuel may create some severe flame-stability problems. These problems can require modification of the burner system in order to operate properly on coal on a long-term basis.

Ash Handling. There are two problems with ash handling: ash accumulation and ash characteristics. When the primary fuel is very clean with a low ash content and the alternate fuel has a high ash content, the accumulation of ash on heat-transfer surfaces and in the bottom of the furnace can shorten the period of time that the unit operates on the alternate fuel. Also, the alternate fuel may have significantly different ash characteristics, which could severely corrode or erode the boiler.

Soot Blowing. Utility systems that use a high-quality fuel as the primary fuel and a lower quality fuel as the alternate must provide adequate soot blowing for the alternate fuel. Soot blowing usually requires a reduction in the electric power available for system load. In some cases, the boiler must be shut down and the heat-transfer surfaces cooled and cleaned if the alternate fuel is burned beyond a short time. Soot blowing can also increase air pollution, creating regulatory problems for utilities operating under strict environmental controls.

Control Systems. Several control systems are associated with the operation of all utility boilers. The major ones are:

- Flow sensors for fuel flow measurements

- Oxygen controls in the boiler used to maintain proper air-to-fuel combustion ratios

- Steam flow and temperature controls.

All these control systems have a specific response time and range over which they function. When switching to alternate fuels, it is sometimes necessary to modify these systems in order to ensure the proper operation of the boiler.

Heat-Transfer Surfaces. As stated earlier, boiler heat-transfer surfaces are sensitive to the particular fuel being burned. They are sensitive to the flame characteristics as well as to the ash composition and quantity. The flame characteristics affect the heat-transfer surfaces because of the flame luminosity or brightness. Heat-transfer surfaces must be protected from direct impact of the flame, which will cause severe localized heating that can permanently damage them. Therefore as fuels are changed, care must be taken that the alternate fuel does not detrimentally alter the way in which heat is transferred from the flame and the gases to the heat-transfer surfaces of the boiler.

The ash quantity and composition are important in three respects: the quantity of ash affects the way in which it is removed from the boiler, the conveying velocities of the ash through the heat-transfer surfaces affect the amount of erosion of those surfaces, and ash quality affects the level of corrosion of the heat-transfer surfaces. An ash's quality can severely affect its corrosion potential and its interaction with the heat-transfer surfaces. For example, high-sodium-content ashes tend to be very corrosive and sticky, causing heat buildup as well as severe corrosion on surfaces. The ash composition also affects its hardness and thus its abrasiveness when coal is being prepared for firing.

Reduced Availability

Many of the problems reviewed in this appendix with regard to operating with an alternate fuel will contribute to a reduced availability of the unit. They create additional loads and stresses on the boiler leading to a higher potential for failure.

Increased Operating Personnel

More personnel are required to burn oil and coal than to burn gas. Coal-fired boilers require almost twice as many operating personnel as gas-fired boilers. Burning oil as an alternate fuel in a gas-fired boiler requires approximately one additional person, and burning coal as an alternate fuel in an oil-fired boiler requires between three and seven additional persons. However, burning oil as an alternate fuel in a coal-fired boiler does not require any additional operating personnel, nor does burning gas as an alternate fuel in an oil-fired boiler.

Alternate Fuel Capability

From a practical standpoint, should the need arise, approximately how much capacity in the contiguous United States has the potential to switch to an

Appendix B

alternate fuel? To estimate that potential capacity, PEDCo Environmental, Inc. surveyed each unit capable of using an alternate fuel. Only those units which the operator reported (to the Federal Energy Regulatory Commission) as capable of operating with an alternate fuel are included in the following potential capacity estimates.[3]

The units were examined for primary/alternate fuel combinations as reported by the operator in 1982. Six possible fuel combinations were reviewed, based on the three basic fossil fuels: coal, oil, and gas.[4] The five combinations discussed are: oil/coal, oil/gas, coal/oil, coal/gas, and gas/oil. In these combinations, the first fuel mentioned is the primary fuel, the second is the alternate fuel. No gas/coal dual-fired units were reported.

PEDCo evaluated each unit using subjective judgment as to the impact of the seven constraints previously discussed. Based on that evaluation, PEDCo assigned each unit a rating on a scale of 1 to 10 to estimate its potential for switching.[5] A low rating indicates less difficulty and thus greater potential for switching, while a rating above 4.5 indicates little potential for switching. These ratings reflect merely the potential capability of a given unit for switching rather than the likelihood that any particular unit would actually switch to the alternate fuel.

The data in Tables B2 through B14 reflect net dependable capacity for units operating on the reported primary fuel and alternate fuel capability in 1982. It is important, however, to note that many units had, or have since, already switched to the alternate fuel. Consequently much of the capacity with "apparent" potential for switching to the alternate fuel shown in the data has, in fact, little or no potential since the units in question may already be using the alternate fuel. For example, in the Pacific Southwest region most oil/gas capacity was already using gas in 1982. However, the potential still exists to switch from the alternate fuel back to the primary fuel if this becomes necessary.

Although the data indicate that approximately 30,000 MW of coal-fired capacity within the contiguous United States could switch to either oil or gas, few units would do so except in the event of an emergency such as a coal strike. In addition, many units that report coal as the alternate fuel may have already switched to coal.

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[3]Fuel conversion, that is, modifying a unit to burn a different primary fuel, is not included in this evaluation.

[4]Five grades of oil are burned in utility boilers: No. 2, No. 4, No. 5, No. 6 low-sulfur, and No. 6 high-sulfur. For purposes of this discussion, gas refers to natural gas that is pipeline quality and is the same at all locations.

[5]For a more detailed discussion of the procedure used to establish the ratings for switching potential, see PEDCo Environmental Inc., "Evaluation of the Engineering Constraints on Fuel Switching at Multi-Fueled Utility Boilers," Final Report (Arlington, Texas, November 1984), pp. 22-27.

Appendix B

The following tables contain regional data on the estimated capacity with potential for switching within the five types of fuel combinations. Generally, using the alternate fuel is more economical for large units than for small units. Since any reported dual-fired capacity that was rated 5.0 and above would only switch to the alternate fuel under extreme conditions, this evaluation focuses on that capacity with a potential for switching of 4.5 or below.

Capacities shown in Tables B2 through B14 reflect the 1982 average net dependable capacity using the primary fuel. Unit capacity may not be the same using the alternate fuel as it is using the primary fuel, as mentioned earlier in this appendix.[6]

In 1982, the New England region had approximately 2,680 MW of dual-fired capacity. There were no coal/gas units in New England; however, about 1,700 MW of capacity could switch from coal to oil. A small amount of gas/oil (28 MW) and oil/coal (23 MW) capacity existed. In addition, New England had 901 MW of oil/gas dual-fired capacity.

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[6]For more detail on how a unit's capacity is affected by changing to the alternate fuel, see the discussion on "derating," in "Evaluation of the Engineering Constraints on Fuel Switching at Multi-Fueled Utility Boilers," pp. 23-26.

Table B2. Estimated Potential Capacity for Fuel-Switching in New England, 1982 (Megawatts)

Rating Category[a]	Oil to Coal	Oil to Gas	Coal to Oil	Coal to Gas	Gas to Oil
1.0, 1.5	0	592 (1)	1,266 (4)	0	--
2.0, 2.5	23 (1)	0	466 (4)	0	--
3.0, 3.5	0	309 (13)	0	0	28 (3)
4.0, 4.5	0	0	0	0	--

[a]A scale (from 1 to 10) judgmentally assigned by PEDCo to estimate a unit's potential to switch to its alternate fuel. Ratings of 5.0 or above indicate extremely little potential for switching and are, therefore, not included in these data.

--=Not applicable.

Note: Data in parentheses are the number of units represented.

Note: Many units may already have switched to the alternate fuel.

Source: Data were compiled by the Electric Power Division, Energy Information Administration, based on a report prepared by PEDCo Environmental Inc., "Evaluation of the Engineering Constraints on Fuel Switching at Multi-Fueled Utility Boilers" (November 1984) and its supplemental data.

Appendix B

The New York region had no coal/oil, coal/gas, or gas/oil capacity in 1982. The region, however, had about 4,230 MW of dual-fired capacity with oil as the primary fuel. About 1,800 MW and 2,500 MW of the oil-fired capacity could switch to coal and gas, respectively.

Table B3. Estimated Potential Capacity for Fuel-Switching in New York, 1982 (Megawatts)

Rating Category[a]	Oil to Coal	Oil to Gas	Coal to Oil	Coal to Gas	Gas to Oil
1.0, 1.5	0	775 (2)	0	0	--
2.0, 2.5	0	1,530 (10)	0	0	--
3.0, 3.5	928 (1)	166 (4)	0	0	--
4.0, 4.5	836 (2)	0	0	0	--

[a]A scale (from 1 to 10) jud[illegible]ally assigned by PEDCo to estimate a unit's potential to switch to its altern[illegible]e fuel. Ratings of 5.0 or above indicate extremely little potential for switching and are, therefore, not included in these data.

--=Not applicable.

Note: Data in parentheses are the number of units represented.

Note: Many units may already have switched to the alternate fuel.

Source: Data were compiled by the Electric Power Division, Energy Information Administration, based on a report prepared by PEDCo Environmental Inc., "Evaluation of the Engineering Constraints on Fuel Switching at Multi-Fueled Utility Boilers" (November 1984) and its supplemental data.

Appendix B

In 1982, about 7,000 MW of capacity in the MAAC region had potential for switching. Around 2,500 MW of capacity that used oil as the primary fuel had switching potential--about 590 MW to coal and 2,000 MW to gas. Approximately 2,700 MW of capacity could switch from coal to oil, 1,226 MW of capacity from coal to gas, and nearly 450 MW of capacity from gas to oil.

Table B4. Estimated Potential Capacity for Fuel-Switching in MAAC, 1982 (Megawatts)

Rating Category[a]	Oil to		Coal to		Gas to Oil
	Coal	Gas	Oil	Gas	
1.0, 1.5	0	979 (3)	2,570 (8)	1,226 (3)	0
2.0, 2.5	385 (2)	870 (8)	151 (4)	0	404 (4)
3.0, 3.5	206 (1)	94 (3)	0	0	44 (2)
4.0, 4.5	0	0	0	0	0

[a]A scale (from 1 to 10) judgmentally assigned by PEDCo to estimate a unit's potential to switch to its alternate fuel. Ratings of 5.0 or above indicate extremely little potential for switching and are, therefore, not included in these data.

Note: Data in parentheses are the number of units represented.

Note: Many units may already have switched to the alternate fuel.

Source: Data were compiled by the Electric Power Division, Energy Information Administration, based on a report prepared by PEDCo Environmental Inc., "Evaluation of the Engineering Constraints on Fuel Switching at Multi-Fueled Utility Boilers" (November 1984) and its supplemental data.

Appendix B

In 1982, the Southeast region had around 11,000 MW of dual-fired capacity. Units with coal as the primary fuel comprised the largest amount of capacity available for switching to oil and gas, around 4,000 MW. This region also had oil-fired capacity with the potential to switch, approximately 2,200 MW to gas and about 400 MW to coal. In addition, the region had 81 MW of gas/oil dual-fired capacity.

Table B5. Estimated Potential Capacity for Fuel-Switching in Southeast, 1982 (Megawatts)

Rating Category[a]	Oil to Coal	Oil to Gas	Coal to Oil	Coal to Gas	Gas to Oil
1.0, 1.5	0	819 (1)	3,076 (5)	2,419 (7)	0
2.0, 2.5	0	678 (6)	1,052 (7)	1,667 (3)	0
3.0, 3.5	102 (1)	677 (17)	0	266 (7)	81 (3)
4.0, 4.5	341 (2)	0	0	0	0

[a]A scale (from 1 to 10) judgmentally assigned by PEDCo to estimate a unit's potential to switch to its alternate fuel. Ratings of 5.0 or above indicate extremely little potential for switching and are, therefore, not included in these data.

Note: Data in parentheses are the number of units represented.

Note: Many units may already have switched to the alternate fuel.

Source: Data were compiled by the Electric Power Division, Energy Information Administration, based on a report prepared by PEDCo Environmental Inc., "Evaluation of the Engineering Constraints on Fuel Switching at Multi-Fueled Utility Boilers" (November 1984) and its supplemental data.

Appendix B

The Florida region, in 1982, excluding the Gulf Power Company, had a total of about 7,000 MW of dual-fired capacity. Of the units fired primarily by oil, about 6,400 MW could switch to gas, but none could switch to coal. The region had no coal/gas capacity. The remaining dual-fired capacity was 200 MW coal/oil and 180 MW gas/oil.

Table B6. Estimated Potential Capacity for Fuel-Switching in Florida, 1982 (Megawatts)

Rating Category[a]	Oil to		Coal to		
	Coal	Gas	Oil	Gas	Gas to Oil
1.0, 1.5	0	4,040 (14)	200 (1)	0	0
2.0, 2.5	0	945 (8)	0	0	0
3.0, 3.5	0	1,376 (34)	0	0	180 (8)
4.0, 4.5	0	0	0	0	0

[a]A scale (from 1 to 10) judgmentally assigned by PEDCo to estimate a unit's potential to switch to its alternate fuel. Ratings of 5.0 or above indicate extremely little potential for switching and are, therefore, not included in these data.

Note: Data in parentheses are the number of units represented.

Note: Many units may already have switched to the alternate fuel.

Source: Data were compiled by the Electric Power Division, Energy Information Administration, based on a report prepared by PEDCo Environmental Inc., "Evaluation of the Engineering Constraints on Fuel Switching at Multi-Fueled Utility Boilers" (November 1984) and its supplemental data.

Appendix B

The ECAR region had approximately 3,000 MW of dual-fired capacity in 1982. Of the units with coal as a primary fuel, about 1,200 MW of capacity could switch to oil and 1,130 MW to gas. In addition, the region had 711 MW of oil capacity that could switch to its alternate fuel, gas. No gas/oil or oil/coal dual-fired capacity existed in this region.

Table B7. Estimated Potential Capacity for Fuel-Switching in ECAR, 1982 (Megawatts)

Rating Category[a]	Oil to		Coal to		
	Coal	Gas	Oil	Gas	Gas to Oil
1.0, 1.5	0	0	1,149 (6)	468 (1)	0
2.0, 2.5	0	0	23 (1)	664 (8)	0
3.0, 3.5	0	711 (18)	31 (3)	0	0
4.0, 4.5	0	0	0	0	0

[a]A scale (from 1 to 10) judgmentally assigned by PEDCo to estimate a unit's potential to switch to its alternate fuel. Ratings of 5.0 or above indicate extremely little potential for switching and are, therefore, not included in these data.

Note: Data in parentheses are the number of units represented.

Note: Many units may already have switched to the alternate fuel.

Source: Data were compiled by the Electric Power Division, Energy Information Administration, based on a report prepared by PEDCo Environmental Inc., "Evaluation of the Engineering Constraints on Fuel Switching at Multi-Fueled Utility Boilers" (November 1984) and its supplemental data.

Appendix B

In 1982, MAIN had about 2,400 MW of dual-fired capacity. No units could switch from oil to coal or from coal to oil. About 1,500 MW of capacity could switch from coal to gas, compared to just over 620 MW that could switch from oil to gas and 262 MW from gas to oil.

Table B8. Estimated Potential Capacity for Fuel-Switching in MAIN, 1982 (Megawatts)

Rating Category[a]	Oil to		Coal to		
	Coal	Gas	Oil	Gas	Gas to Oil
1.0, 1.5	0	0	0	640 (2)	0
2.0, 2.5	0	583 (9)	0	820 (7)	0
3.0, 3.5	0	39 (3)	0	55 (2)	262 (23)
4.0, 4.5	0	0	0	0	0

[a]A scale (from 1 to 10) judgmentally assigned by PEDCo to estimate a unit's potential to switch to its alternate fuel. Ratings of 5.0 or above indicate extremely little potential for switching and are, therefore, not included in these data.

Note: Data in parentheses are the number of units represented.

Note: Many units may already have switched to the alternate fuel.

Source: Data were compiled by the Electric Power Division, Energy Information Administration, based on a report prepared by PEDCo Environmental Inc., "Evaluation of the Engineering Constraints on Fuel Switching at Multi-Fueled Utility Boilers" (November 1984) and its supplemental data.

Appendix B

In 1982, about 3,400 MW of capacity in MAPP had potential for switching. No units could switch from oil to coal; however, 622 MW of capacity could switch from oil to gas. Units with coal as the primary fuel had approximately 500 MW and 2,000 MW of capacity that could switch to oil and gas, respectively. Gas/oil units reflected about 270 MW of switching capacity.

Table B9. Estimated Potential Capacity for Fuel-Switching in MAPP, 1982 (Megawatts)

Rating Category[a]	Oil to Coal	Oil to Gas	Coal to Oil	Coal to Gas	Gas to Oil
1.0, 1.5	0	0	240 (1)	0	0
2.0, 2.5	0	0	85 (1)	1,115 (8)	107 (1)
3.0, 3.5	0	622 (21)	177 (10)	865 (33)	165 (12)
4.0, 4.5	0	0	0	0	0

[a]A scale (from 1 to 10) judgmentally assigned by PEDCo to estimate a unit's potential to switch to its alternate fuel. Ratings of 5.0 or above indicate extremely little potential for switching and are, therefore, not included in these data.

Note: Data in parentheses are the number of units represented.

Note: Many units may already have switched to the alternate fuel.

Source: Data were compiled by the Electric Power Division, Energy Information Administration, based on a report prepared by PEDCo Environmental Inc., "Evaluation of the Engineering Constraints on Fuel Switching at Multi-Fueled Utility Boilers" (November 1984) and its supplemental data.

Appendix B

The largest amount of estimated capacity (about 22,000 MW) available for switching in 1982 in the SPP region was gas to oil. Units with coal as the primary fuel had about 3,100 MW and 1,700 MW that could switch to gas and oil, respectively. Of the dual-fired oil capacity, none had the potential to switch to coal, while about 3,300 MW could switch to gas.

Table B10. Estimated Potential Capacity for Fuel-Switching in SPP, 1982 (Megawatts)

Rating Category[a]	Oil to		Coal to		
	Coal	Gas	Oil	Gas	Gas to Oil
1.0, 1.5	0	3,128	1,504	2,358	16,144
		(8)	(4)	(8)	(47)
2.0, 2.5	0	179	185	766	4,329
		(9)	(7)	(14)	(45)
3.0, 3.5	0	0	0	0	1,758
					(65)
4.0, 4.5	0	0	0	0	0

[a]A scale (from 1 to 10) judgmentally assigned by PEDCo to estimate a unit's potential to switch to its alternate fuel. Ratings of 5.0 or above indicate extremely little potential for switching and are, therefore, not included in these data.

Note: Data in parentheses are the number of units represented.

Note: Many units may already have switched to the alternate fuel.

Source: Data were compiled by the Electric Power Division, Energy Information Administration, based on a report prepared by PEDCo Environmental Inc., "Evaluation of the Engineering Constraints on Fuel Switching at Multi-Fueled Utility Boilers" (November 1984) and its supplemental data.

Appendix B

Approximately 30,000 MW of the dual-fired capacity in the ERCOT region had potential in 1982 for switching. Most of that capacity (about 29,000 MW) were gas-fired units that could use oil as the alternate fuel. The remaining 1,470 MW of capacity were coal-fired units, of which 810 MW could switch to oil and 660 MW to gas. No oil/coal or oil/gas dual-fired units existed.

Table B11. Estimated Potential Capacity for Fuel-Switching in ERCOT, 1982 (Megawatts)

Rating Category[a]	Oil to		Coal to		
	Coal	Gas	Oil	Gas	Gas to Oil
1.0, 1.5	0	0	810 (2)	660 (1)	16,397 (37)
2.0, 2.5	0	0	0	0	6,787 (44)
3.0, 3.5	0	0	0	0	5,570 (100)
4.0, 4.5	0	0	0	0	0

[a]A scale (from 1 to 10) judgmentally assigned by PEDCo to estimate a unit's potential to switch to its alternate fuel. Ratings of 5.0 or above indicate extremely little potential for switching and are, therefore, not included in these data.

Note: Data in parentheses are the number of units represented.

Note: Many units may already have switched to the alternate fuel.

Source: Data were compiled by the Electric Power Division, Energy Information Administration, based on a report prepared by PEDCo Environmental Inc., "Evaluation of the Engineering Constraints on Fuel Switching at Multi-Fueled Utility Boilers" (November 1984) and its supplemental data.

Appendix B

The Pacific Northwest region's dual-fired units in 1982 totaled nearly 1,700 MW. Most of that capacity (around 1,300 MW) used coal as its primary fuel and gas as the alternate fuel. A small amount of capacity could switch from coal to oil (22 MW) and from oil to gas (70 MW). The region also had around 233 MW of capacity that could switch from gas to oil. No oil/coal dual-fired units existed.

Table B12. Estimated Potential Capacity for Fuel-Switching in the Pacific Northwest, 1982 (Megawatts)

Rating Category[a]	Oil to		Coal to		Gas to Oil
	Coal	Gas	Oil	Gas	
1.0, 1.5	0	0	0	944 (6)	0
2.0, 2.5	0	70 (1)	0	384 (8)	0
3.0, 3.5	0	0	22 (1)	0	233 (15)
4.0, 4.5	0	0	0	0	0

[a]A scale (from 1 to 10) judgmentally assigned by PEDCo to estimate a unit's potential to switch to its alternate fuel. Ratings of 5.0 or above indicate extremely little potential for switching and are, therefore, not included in these data.

Note: Data in parentheses are the number of units represented.

Note: Many units may already have switched to the alternate fuel.

Source: Data were compiled by the Electric Power Division, Energy Information Administration, based on a report prepared by PEDCo Environmental Inc., "Evaluation of the Engineering Constraints on Fuel Switching at Multi-Fueled Utility Boilers" (November 1984) and its supplemental data.

Appendix B

Most of the dual-fired capacity (about 22,000 MW) in the Pacific Southwest region used oil as the primary fuel with gas as the alternate fuel in 1982. There was no oil/coal dual-fired capacity in this region. Of the units using coal as the primary fuel, 330 MW of capacity could switch to oil and approximately 1,580 MW to gas. Gas/oil dual-fired units had about 2,200 MW of switching capacity.

Table B13. Estimated Potential Capacity for Fuel-Switching in the Pacific Southwest, 1982 (Megawatts)

Rating Category[a]	Oil to		Coal to		Gas to Oil
	Coal	Gas	Oil	Gas	
1.0, 1.5	0	19,343 (82)	330 (3)	1,580 (2)	182 (1)
2.0, 2.5	0	2,694 (49)	0	0	679 (7)
3.0, 3.5	0	0	0	0	1,346 (40)
4.0, 4.5	0	0	0	0	0

[a]A scale (from 1 to 10) judgmentally assigned by PEDCo to estimate a unit's potential to switch to its alternate fuel. Ratings of 5.0 or above indicate extremely little potential for switching and are, therefore, not included in these data.

Note: Data in parentheses are the number of units represented.

Note: Many units may already have switched to the alternate fuel.

Source: Data were compiled by the Electric Power Division, Energy Information Administration, based on a report prepared by PEDCo Environmental Inc., "Evaluation of the Engineering Constraints on Fuel Switching at Multi-Fueled Utility Boilers" (November 1984) and its supplemental data.

Appendix B

In 1982, an estimated 128,970 MW of the dual-fired capacity available in the 48 contiguous States could switch to an alternate fuel (Table B14). About 43 percent (or 54,696 MW) of that capacity could switch from gas to oil. Of that gas/oil switching capacity, 50,985 MW were in the ERCOT (28,754 MW) and the SPP (22,231 MW) regions. No gas/coal dual-fired units were reported in 1982.

Oil/gas dual-fired units provided around 41,219 MW of potential switching capacity. Of that potential to switch from oil to gas, over one-half (22,037 MW) was in the Pacific Southwest region. For coal-fired units, 13,337 MW and 16,897 MW of capacity could switch to oil or gas, respectively. The Southeast region had the highest coal-fired switching capacity (around 8,500 MW to either oil or gas).

Table B14. Summary of Regional Estimated Potential Fuel-Switching Capacity, 1982 (Megawatts)

Region	Oil to Coal	Oil to Gas	Coal to Oil	Coal to Gas	Gas to Oil	Total Potential
New England	23	901	1,732	0	28	2,684
New York	1,764	2,471	0	0	0	4,235
MAAC	591	1,943	2,721	1,226	448	6,929
Southeast	443	2,174	4,128	4,352	81	11,178
Florida	0	6,361	200	0	180	6,741
ECAR	0	711	1,203	1,132	0	3,046
MAIN	0	622	0	1,515	262	2,399
MAPP	0	622	502	1,980	272	3,376
SPP	0	3,307	1,689	3,124	22,231	30,351
ERCOT	0	0	810	660	28,754	30,224
Pacific Northwest	0	70	22	1,328	233	1,653
Pacific Southwest	0	22,037	330	1,580	2,207	26,154
Total	2,821	41,219	13,337	16,897	54,696	128,970

Note: The estimated capacity shown in this table was based on a scale (from 1 to 10) judgmentally assigned by PEDCo to estimate a unit's potential to switch to its alternate fuel. Ratings of 5.0 or above indicate extremely little potential for switching and are, therefore, not included in these data.

Note: Many units may already have switched to the alternate fuel.

Source: Data were compiled by the Electric Power Division, Energy Information Administration, based on a report prepared by PEDCo Environmental Inc., "Evaluation of the Engineering Constraints on Fuel Switching at Multi-Fueled Utility Boilers" (November 1984) and its supplemental data.

Factors other than engineering constraints, such as fuel cost, accessibility of transportation for fuels, and regulatory/ environmental constraints, can be critical when determining whether to use the primary or the alternate fuel. For example, the ERCOT, SPP, and Pacific Southwest regions are fairly close to gas

Appendix B

pipelines, thus gas is reasonably accessible. Consequently, for these dual-fired units, the cost and availability of the two respective fuels (gas and oil) are probably major factors in deciding whether to use the primary or the alternate fuel.

Transmission Constraints

Background

Transmission systems generally consist of overhead wiring and occasionally of underground or underwater cables for transmitting power, transformers for converting from one voltage level to another, protecting devices such as circuit breakers and relays, and support physical structures such as transmission towers and substations. While the voltage and conductor size of a transmission line are basic to the determination of its capacity to transmit power, system factors such as transmission line length, relative system phase angles, capacity of terminal equipment, and system operating constraints may also be the controlling factors.

Bulk power transmission constitutes a network primarily of high and extra-high voltage (EVH) alternating current (ac), usually 138 to 765 kilovolts 3-phase with a frequency of 60 Hertz (cycles per second). These transmission systems are designed to interconnect generating plants and electric utility systems and to carry power from plants to major load centers.

High voltage direct current (HVDC) transmission, +-250 to +-400 kilovolts, is emerging as an attractive complement to ac power transmission. Direct-current (dc) links play a special role in long distance transmission and interconnection between regions. In many places it is virtually impossible to link neighboring ac systems together because such connections would be unstable during adverse system conditions. The dc links can be used to control power flow between systems and are unaffected by conditions which might lead to instability in ac systems. The major disadvantage is the cost of a rectifier that converts ac to dc for transmission and the cost of the inverter that converts dc to ac at the end of the transmission line.

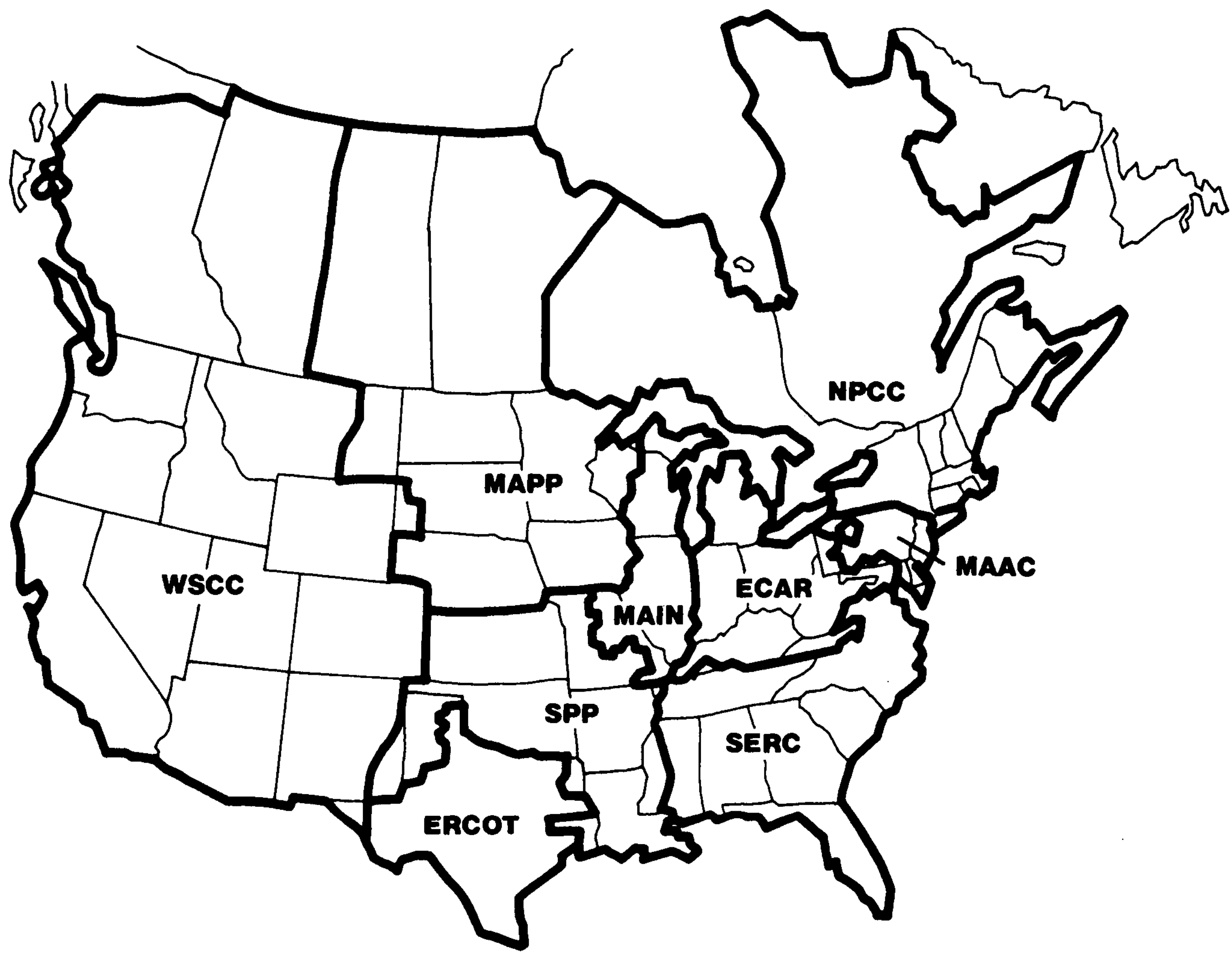
United States Power System

Most of the major electric power systems of the United States and Canada are members of the North American Electric Reliability Council (NERC), which consists of nine regions (Figure B2). NERC directs its efforts to improve the reliability and adequacy of bulk power supply of the electric utility systems in North America.

There are three major power networks in the 48 contiguous States: (1) the eastern two-thirds of the country, (2) most of the State of Texas, and (3) the western section of the Nation. In each system, the utilities of each of the three networks are continuously synchronized so that they operate with the same voltage, phase position, and at the same frequency. The nine NERC regions mesh perfectly into the three synchronous systems. The Texas system is the same as the Electric Reliability Council of Texas (ERCOT), and the western network is the same as the

Appendix B

Figure B2. North American Electric Reliability Council (NERC) Regions



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interpool Network

MAPP
Mid-continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

Source: North American Electric Reliability Council.

Appendix B

territory covered by the Western Systems Coordinating Council (WSCC). Numerous interregional connections exist between the Eastern interconnected NERC regions.

The intention of the NERC large-scale electric power system interconnection is to achieve economical and reliable electric energy generation and transmission. The economic aspect is brought about through the reduction of spinning reserve or standby generation to meet sudden load increases or system maintenance requirements and the minimization of fuel cost. Two examples of the minimization of fuel costs are the transfer of coal-fired electric energy from ECAR to MAAC and from Southeast to Florida to displace more expensive oil-fired energy. The reliability of the interconnected system is also enhanced by the capability of transferring power readily from one area to another within the system. However, the multiple interconnections can make the system more vulnerable to instability because of the complexity of multiarea operations.

Power Pools

Major economic and reliability benefits exist for utilities that coordinate their facilities and operations and form power pools. Among them are a reduction in generating equipment investment and operating costs by the sharing of reserves and the minimization of fuel costs, and emergency assistance between utilities. The degree of joint planning and operations in power pools can range from very loose arrangements for energy transfers to coordinated planning and operations to completely integrated operations. Operations have been coordinated among electric utilities for many years. A recent well-publicized example occurred after the Iranian oil crisis in 1979 when the electric utility industry developed procedures for monitoring wholesale interchange of power to assure that maximum energy transfers were taking place to displace oil with other fuels.

In order for utilities to participate in regional coordination or power pool agreements, the individual utilities have to give up some of their management control and authority. Many technical, economic, geographic, legal, and financial factors have to be considered in developing a power pool agreement. Some examples of utility coordination agreements are the New England Power Pool (NEPOOL), the New York Power Pool (NYPP), the Pennsylvania-New Jersey-Maryland (PJM) Pool, and Michigan Electric Coordination Systems (MECS). There are approximately 17 power pools in the United States which vary widely in functions, procedures, and cost allocation schemes. At present, 59 percent of electric generating capacity in the contiguous United States is owned by interconnected utilities with formal pooling agreements.[7]

Impediments to Transfers

Among the impediments to transfer of bulk power through existing transmission facilities are economic, regulatory, legal, and technical or engineering constraints. The following discussion briefly describes some of the nontechnical

[7] Federal Energy Regulatory Commission, Power Pooling in the United States (Washington, DC, November 1980).

Appendix B

limitations to the long-distance transfer of power through existing transmission facilities, and then concentrates on engineering constraints.

Economic Considerations

The difference in electricity generation prices influences both the power quantity of a transfer and the distance of the transfer between the seller and buyer. If the generation cost difference is small, large power transfers over long distances will result in electrical transmission line losses that cancel out the savings in generation costs. When cost differentials are small, power transfers are small and take place only among neighboring utilities.

The use of bulk power transmission to lower energy costs has grown dramatically since 1973 when rising oil and gas prices caused wide divergence in the cost of electricity produced from various fuels. The economy interchange of electric power benefits both the sending and receiving systems.

Regulatory and Legal Impediments

The regulatory and legal impediments for electrical power transfer primarily relate to the licensing and construction of new transmission facilities rather than transferring electricity over existing lines. For example, in some situations, taxes on energy exported from a State inhibit sales from systems within that State and joint generation projects involving utilities outside that State.

Engineering Constraints

Generally, the power a transmission line can transmit is limited either by a thermal limit or by a system stability limit which is set as part of the utility's operating policy. Thermal limits usually govern in the case of more compact, predominantly eastern utilities, while stability limits are likely to be more restrictive in the case of the more widely dispersed midwestern and western utilities.

Thermal limits are established to prevent the build-up of heat in the conductor and the insulation when the cables are insulated. Heat causes overhead conductors to sag and increases the possibility of cable insulation failure. The damage is cumulative and increases drastically with temperature. The allowable current carrying ratings of conductors are calculated on the basis of allowable operating temperatures and incorporate empirical criteria for "loss of life," which refers to the cumulative damage of heat. Operating a conductor over its rated capacity, which is done in emergencies, can be traded for a decrease in expected operating life.

Stability limits of systems are dependent on the electrophysical relations governing the transfer of power over transmission lines in alternating current systems. Transfer of power at a given voltage can be increased only up to a certain level beyond which it becomes impossible to maintain synchronous operation between generators at the respective ends of the lines. Following a disturbance

Appendix B

in the system, such as a fault, it is possible for a generator to regain synchronism with the rest of the system; but this ability is limited and depends on the design of the protection system. System operating conditions are established to maintain operation within safe limits while allowing for the occurrence of some disturbances.

Transmission systems may constrain the supply of electric energy because transmission outages or capacity limits may prevent the delivery of power to some loads even if generating capacity is adequate. Transmission lines may be out of service due to maintenance, operation of protective equipment (for example, a circuit breaker open to clear a fault), failure of cable insulation, failure of other equipment such as transformers or circuit breakers, or other events (fire, lightning, etc.).

The following discussion describes some of the engineering constraints to increasing the amount of power transferred over long distances through existing transmission networks.[8]

Parallel Paths. The transmission system is a network in which electricity flows generally uncontrolled from generation to the point of use through all of the parallel network paths simultaneously, following physical laws. The greater the distance, the more paths are involved, and the likelihood is greater that a system which is neither a buyer nor seller will experience flow through its facilities. Limitations to the transfer can arise in the facilities of a system which is not a party to the transaction. Also, that system may be in a regulatory jurisdiction different from that of the transacting parties.

Operating Limitations. There are limitations to transfers presented by technical restrictions on equipment operation or system operation. Some of these are the inability to lower the output of a generator below a certain point, a requirement of reliable operation that spinning reserve be maintained and well-dispersed, the electrical requirement that reactive power be generated so that transfers can be consummated, and the damaging stresses that can result from frequently starting and stopping rotating equipment.

Maintenance. Another technical, constantly changing limitation is that line and terminal equipment must be removed from service for maintenance. Removal of part of the transmission system reduces the ability to make transfers. One NERC Council has records to show that, for half the time, five or more bulk power lines are out of service.

Subsynchronous Resonance. The subsynchronous resonance phenomenon associated with series capacitor compensated lines in the West has limited transfer capabilities. Series capacitors increase transmission line capability. However, under certain conditions, the series capacitors will cause periodic voltage oscillations on the transmission lines which interact with and damage generators. Thus, full capabilities of the compensated lines cannot be utilized. Engineering is

[8]North American Electric Reliability Council, A Report for the National Association of Regulatory Utility Commissions Committee on Electricity, Impediments to Transfer (Princeton, New Jersey, May 30, 1984), pp. 7-8.

proceeding with mitigating devices, but a universally applicable design has not been developed.

Reliability Limitations. Last in this brief list, but certainly not least, are reliability limitations. The philosophy and practice of providing a predetermined amount of line capability above that required for normal operation is well-founded. This amount of line capacity above that required for normal operation must be carefully planned for, and observed in operation. An adequate provision must be made for the automatic redistribution of power that occurs in an ac network when changes take place, such as generator or line outages, or changes in transfers or load patterns. This practice limits the amount of transfers but also reduces the chance of widespread cascading blackouts.

Transmission Constraints of NERC Regions

Transmission constraints, both nontechnical and technical, are not static but vary over time for each NERC region. For instance, transmission lines are periodically taken out of service for maintenance or repair, new transmission lines are constructed, regulations can be added or modified affecting the transmission of power, transmission lines can be modified (for example, increasing the voltage) to increase capacity or improve performance, and the nature of power transfers can change.

In recent years, the nature of power transfers among systems in the three-region area consisting of NPCC, MAAC, and ECAR has changed, causing significantly different power flow patterns from those previously experienced. The large disparity between the cost of electricity generated from oil and that produced by non-oil-fired sources has resulted in large power transfers into eastern MAAC, southeastern New York, and into New England to displace oil-fired generation. Transmission lines originally built primarily for reliability purposes are now being used to move economy power, which often reaches the capabilities of the lines.

Typical power transfers are: from Ontario to New York and Michigan; from ECAR to MAAC; from American Electric Power to Michigan; from Hydro-Quebec to New York, New Brunswick, and Ontario; and from New Brunswick to New England. The combination of these multiple transfers on the interconnected network has resulted in the need to restrict power transfer schedules in order to avoid exceeding transmission limitations. In some instances, systems have not been able to schedule economy transfers because of transmission restrictions in a neighboring system.[9]

Some of the constraints of bulk power transmission for several NERC regions are discussed below.

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[9]Federal Power Commission, A Report to the President, Prevention of Power Failures, Volume 1 (Washington, DC, July 1967).

Appendix B

Northeast Power Coordinating Council (NPCC)

The NPCC region represents investor-owned and public utility systems serving about 43 million people in the northeastern United States and eastern Canada, an area of approximately 1 million square miles.[10] In the United States, NPCC members are participants in either the New England Power Pool (NEPOOL) or New York Power Pool (NYPP).

New York State north-south transmission is inadequate to allow full use of available energy from Canada or even to take advantage of all non-oil-fired generation in NYPP. A 345-KV double circuit reinforcement (referred to as Marcy-South), which would ease this situation, is scheduled for completion in 1987 but is now in jeopardy of being scaled down to a single circuit reinforcement. Should the facility not be constructed as proposed, the ability to transfer economy energy, and at the same time maintain the reliability of the interconnected network, could be reduced. Since the substantial fuel cost differential between oil-fired and non-oil-fired generation is expected to continue in the forseeable future, NPCC systems are pursuing plans to construct transmission lines to accommodate increased power transfers.

Mid-Atlantic Area Council (MAAC)

The MAAC region consists of 11 member systems and 5 associates serving more than 1 million people over a 48,700-square-mile area. The MAAC region is an example of using the transmission system to displace high cost oil- and gas-fired generation by importing coal-fired economy generation from ECAR. The most limiting bulk power transmission system facilities were loaded in 1982 to 100 percent of their capability over 40 percent of the time, and to 90 percent or more of their capability more than 65 percent of the time. In 1983, the most limiting facilities were loaded to 100 percent of their capability more than 70 percent of the time, and to 90 percent or more of their capability almost 95 percent of the time. These high and increasing levels of use in MAAC indicate how transmission systems in either oil- or gas-dependent areas are being utilized. MAAC's major west-to-east transmission path utilization averaged more than 97 percent in 1983.[11]

Although acceptable reliability standards are not exceeded for the sake of operating economy, operating the region's bulk power system closer to its thermal and reactive limits for long periods of time for economy transfers is a source of concern. At present, MAAC is experiencing substantial parallel path flows as a result of neighboring systems making economy purchases.

Typically, imports from ECAR of about 3,000 MW are now taking place to displace oil-fired generation. Internal voltage limitations on the MAAC bulk transmission

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[10]North American Electric Reliability Council, 14th Annual Review of Overall Reliability and Adequacy of Bulk Power Supply in the Electric Utility Systems of North America (Princeton, New Jersey, 1984), p. 44.

[11]North American Electric Reliability Council, 14th Annual Review, p. 33.

Appendix B

system are expected to restrict these oil displacements to these values for the near term. However, efforts to reinforce the network capability to facilitate additional oil displacement transfers are continuing. During 1983, the addition of bulk power shunt capacitators, the conversion of the Alburtis-Hosensack 230-kV line to 500-kV operation and the installation of a series reactor at the Nottingham terminal of the Graceton-Nottingham 230-kV line are expected to further reduce the MAAC voltage limitation and improve transfer capability.

Completion of the BG&E/PEPCO/VEPCO 500-kV loop around the Washington metropolitan area has been delayed until 1986. When completed, the loop will improve stability in the Baltimore/Washington area and increase the MAAC transfer capability in the adjacent ECAR and Virginia-Carolina area (VACAR) regions. Transmission limitations at the interface of these regions have in the past restricted the deliveries of available MAAC and NPCC capacity and energy to deficient regions. On one occasion the limitations resulted in the dropping of major blocks of customer load in a deficient system adjacent to MAAC. Based on current projections, further delay of the loop would severely impair the reliability of the Baltimore/-Washington area of the MAAC region. Pending completion of this vital loop, special coordinated, interregional operating procedures have been developed in order to maximize deliveries during operating capacity emergencies while protecting the integrity of the bulk power systems.

Southeast Electric Reliability Council (SERC)

The SERC region includes 27 utility member systems located in 9 southeastern States.[12] SERC is divided into 4 subregions: the Florida Peninsula (Florida), the geographical bounds of the Southern electric system (Southern), the geographical bounds of the Tennessee Valley Authority (TVA), and the Virginia-Carolina area (VACAR). The SERC region occupies a geographic territory of approximately 345,650 square miles.

During 1981, Florida imported 4,337 GWh of coal-by-wire energy from the Southern Subregion while experiencing 28 occurrences of electrical system separation caused by system disturbances. With the addition of major 500-kV and 230-kV transmisson facilities during 1982 and 1983, Florida almost tripled its imports of coal power to 12,793 GWh during 1983, and experienced no electrical system separation.

Significant economy transfers between VACAR systems and between the VACAR subregion and other subregions or regions meet with negligible transmission constraints today. The planned SERC transmission line additions will increase transfer capabilities within SERC and between SERC and other NERC regions.

Western Systems Coordinating Council (WSCC)

WSCC encompasses approximately 1.8 million square miles of territory in 14 western States, plus parts of 2 Canadian provinces. The region is subdivided into four areas: the Northwest Power Pool Area, which depends heavily on hydroelectric

[12] North American Electric Reliability Council, 14th Annual Review, p. 50.

generation; the Rocky Mountain Power Area, with a generation mix of 28 percent hydroelectric and 60 percent coal-fired; the Arizona-New Mexico Power Area, with 37 percent gas/oil and 57 percent coal-fired generation; and the California Southern Nevada Power Area, which depends heavily on oil-and gas-fired generation.[13]

The current levels of available economy energy are subjecting the interconnected system to high loadings that approach marginal operating reliability. Several of the WSCC Areas continue to experience transmission limitations that impede the transfer of desired power levels. These limitations are compounded by a component of power that flows on transmission facilities other than those on which it is scheduled. As a result of this "parallel path flow," there was a significant number of hours during 1983 when it was necessary to curtail firm and/or economy surplus power transfers within WSCC to reduce transmission overloads.

The Southern California Edison Company Devers-Valley-Serrano 500-kV line is presently planned for operation in 1986, a 2-year delay from the original planned date of 1984. The impact of this delay will be steadily deteriorating quality of service in the Hemet-Perris area, with low voltages and customer outages becoming more common. The delay will also restrict the Arizona-California transfer capability by some 400 MW, resulting in more frequent curtailment of economy energy imports to California.[14]

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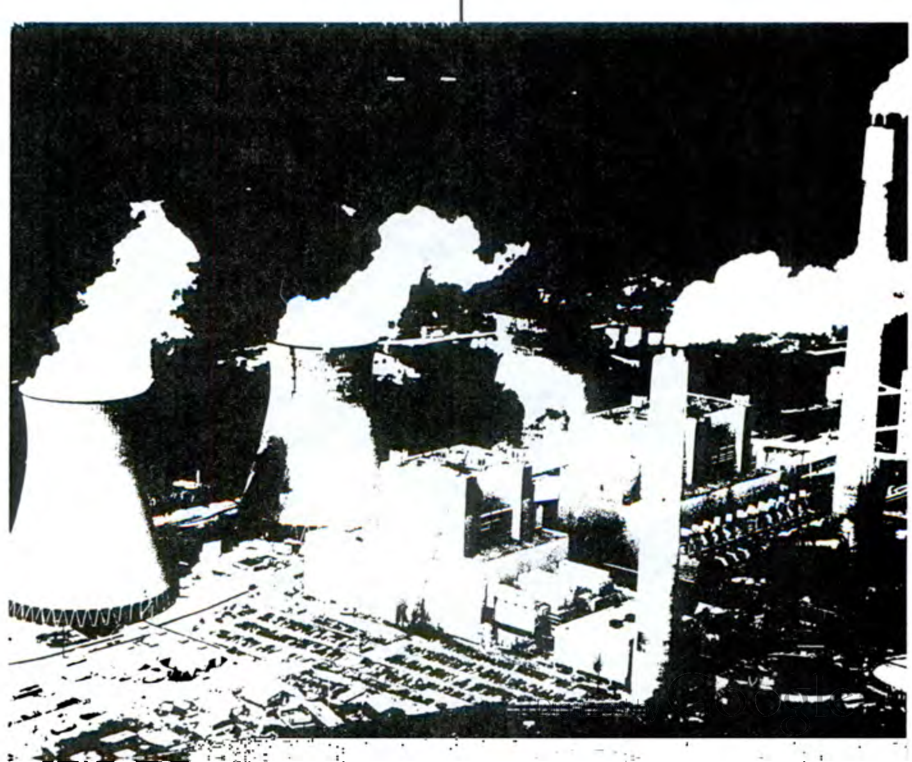
[13]North American Electric Reliability Council, <u>14th Annual Review</u>, p. 60.

[14]Western Systems Coordinating Council, "Coordinated Bulk Power Supply Program, 1983-1993," Draft Report (April 1, 1984), p. 6A-14.

Appendix C

Annual Net Generation, Fossil-Fuel Costs, Capacity, and Capacity Utilization by Region



Appendix C

This appendix provides annual data from 1972 through 1982 by region. See the Executive Summary, Figure ES1, for a map showing the 12 regions designated for this report. For each region, tables are provided that indicate: (1) net generation (defined as total gross generation minus plant use) by fuel type, including the share of total regional generation for each fuel type, (2) fossil-fuel costs, (3) monthly average fossil-fuel steam capacity by fuel type, and (4) fossil-fuel steam capacity utilization ratios for each fuel type. Data for fossil-fuel steam capacity include both single-fuel and multifuel boilers.

Table C1. Net Generation of Electricity in the New England Region, 1972-1982 (Gigawatthours)

Year	Total[a]	Coal	Share (%)	Oil	Share (%)	Gas	Share (%)	Nuclear	Share (%)	Hydro-electric	Share (%)
1972	68,065	3,296	5	49,562	73	642	1	9,500	14	5,065	7
1973	72,408	2,888	4	49,112	68	534	1	14,372	20	5,502	8
1974	69,519	5,147	7	41,560	60	862	1	16,911	24	5,039	7
1975	69,927	4,377	6	40,763	58	192	*	19,979	29	4,616	7
1976	75,857	1,972	3	43,198	57	270	*	25,183	33	5,234	7
1977	76,356	2,523	3	43,058	56	273	*	25,530	33	4,970	7
1978	79,841	1,966	2	45,436	57	124	*	28,028	35	4,276	5
1979	78,357	2,890	4	43,359	55	734	1	26,730	34	4,612	6
1980	78,285	4,539	6	47,183	60	576	1	22,450	29	3,488	4
1981	76,911	4,468	6	41,196	54	796	1	25,785	34	4,641	6
1982	77,005	11,199	15	33,397	43	1,471	2	26,497	34	4,398	6

[a]Total includes generation from refuse and wood.
*=Less than 0.5 percent.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Appendix C

Table C2. Fossil-Fuel Costs for Electric Generation in the New England Region, 1972-1982 (Dollars per Million Btu)

Year	Weighted Average[a]	Coal[b]	Oil[c]	Gas[d]
1972	0.54	0.48	0.55	0.50
1973	0.73	0.53	0.75	0.52
1974	1.85	1.15	1.97	1.29
1975	1.89	1.24	1.95	1.25
1976	1.82	1.25	1.84	1.54
1977	2.10	1.30	2.15	1.89
1978	1.95	1.48	1.97	1.88
1979	2.85	1.53	2.93	2.65
1980	3.90	1.73	4.12	3.44
1981	4.66	2.14	5.00	3.77
1982	3.95	2.35	4.43	4.03

[a]Quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plants.

[b]Includes anthracite, bituminous coal, subbituminous coal and lignite.

[c]Includes fuel oil Nos. 2, 4, 5, and 6 as well as crude oil, topped crude, kerosene, and jet fuel.

[d]Includes natural gas, coke oven gas, blast furnace gas, and refinery gas.

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Appendix C

Table C3. Monthly Average Available Fossil Fuel Steam Capacity by Fuel in the New England Region, 1972-1982 (Megawatts)

	Capacity					
	Single Fuel			Multifuel		
Year	Coal	Oil	Gas	Coal	Oil	Gas
1972	0	7,023.67	0	484.17	705.00	224.50
1973	45.08	6,381.75	0	2,052.92	2,230.42	350.67
1974	45.08	5,988.83	0	1,885.25	2,197.83	465.83
1976	45.08	6,432.75	0	2,614.75	3,073.92	353.83
1977	17.50	5,806.58	0	2,732.67	3,665.92	879.75
1978	34.92	5,760.92	0	2,734.75	3,612.42	872.92
1979	292.33	7,912.92	0	1,985.50	2,261.00	350.42
1980	292.33	7,961.08	0	1,935.92	2,280.92	349.25
1981	293.17	6,995.50	0	1,413.33	1,796.92	350.58
1982	175.58	7,548.58	0	1,298.17	2,096.42	833.50

Source: Monthly averages for each year were calculated by the Energy Information Administration, Electric Power Division, based on monthly data from PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Table C4. Capacity Utilization Ratios for Fossil-Fuel Steam in the New England Region, 1972-1982

Year	Coal	Oil	Gas
1972	0.6798	0.6763	0.3756
1973	0.1489	0.6072	0.1304
1974	0.2894	0.5343	0.1592
1975	0.1727	0.4622	0.0156
1976	0.0802	0.4822	0.0665
1977	0.0992	0.4854	0.0331
1978	0.0753	0.4877	0.0141
1979	0.1027	0.4343	0.1968
1980	0.2099	0.4684	0.1593
1981	0.2717	0.4802	0.2168
1982	0.8051	0.3644	0.1853

Note: Capacity utilization ratios for each fuel were calculated by Energy Information Administration, Electric Power Division, by taking the ratio of actual generation for the year to the potential generation based on the highest reported monthly available capacity for the year.

Sources: •Generation data: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms. •Capacity data: PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C5. Net Generation of Electricity in the New York Region, 1972-1982 (Gigawatthours)

Year	Total[a]	Coal	Share (%)	Oil	Share (%)	Gas	Share (%)	Nuclear	Share (%)	Hydro-electric	Share (%)
1972	101,878	14,083	14	47,975	47	5,812	6	6,465	6	27,542	27
1973	105,783	13,507	13	50,388	48	5,506	5	7,227	7	29,156	28
1974	103,750	14,657	14	48,246	47	2,935	3	9,272	9	28,639	28
1975	107,280	13,808	13	51,188	48	1,039	1	13,111	12	28,135	26
1976	108,949	13,645	13	50,589	46	452	*	15,659	14	28,603	26
1977	112,574	14,884	13	51,304	46	355	*	20,590	18	25,441	23
1978	113,121	13,869	12	51,619	46	100	*	21,701	19	25,832	23
1979	105,318	13,962	13	40,064	38	6,473	6	18,507	18	26,240	25
1980	108,603	14,469	13	37,834	35	10,766	10	19,276	18	26,241	24
1981	105,833	14,402	14	36,760	35	11,566	11	17,444	16	25,658	24
1982	101,936	15,254	15	32,932	32	13,974	14	14,438	14	25,329	25

[a]Total includes generation from refuse and wood.
*=Less than 0.5 percent.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Appendix C

Table C6. Fossil-Fuel Costs for Electric Generation in the New York Region, 1972-1982 (Dollars per Million Btu)

Year	Weighted Average[a]	Coal[b]	Oil[c]	Gas[d]
1972	0.56	0.48	0.59	0.46
1973	0.73	0.50	0.80	0.50
1974	1.77	1.06	2.03	0.69
1975	1.78	1.18	1.95	0.88
1976	1.76	1.13	1.93	1.07
1977	1.97	1.17	2.20	1.41
1978	1.88	1.29	2.04	1.49
1979	2.50	1.36	2.98	2.29
1980	3.28	1.47	4.26	2.67
1981	4.02	1.71	5.11	3.49
1982	3.81	1.83	4.70	3.91

[a]Quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plants.

[b]Includes anthracite, bituminous coal, subbituminous coal, and lignite.

[c]Includes fuel oil Nos. 2, 4, 5, and 6 as well as crude oil, topped crude, kerosene, and jet fuel.

[d]Includes natural gas, coke oven gas, blast furnace gas, and refinery gas.

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Appendix C

Table C7. Monthly Average Available Fossil Fuel Steam Capacity by Fuel in the New York Region, 1972-1982 (Megawatts)

Year	Capacity: Single Fuel Coal	Single Fuel Oil	Single Fuel Gas	Multifuel Coal	Multifuel Oil	Multifuel Gas
1972	2,325.83	4,093.67	126.00	2,368.00	5,005.67	2,536.17
1973	2,304.75	4,281.75	2.67	2,526.25	5,058.92	2,636.08
1974	2,311.75	4,361.42	2.67	2,445.25	5,085.42	2,617.08
1975	2,311.75	4,921.33	2.67	2,345.17	5,102.92	2,728.25
1976	2,317.08	5,323.08	2.67	2,382.42	5,113.00	2,664.67
1977	2,320.58	6,009.17	2.67	2,292.83	4,884.08	2,516.83
1978	2,320.50	6,371.58	2.67	2,310.33	4,852.17	2,484.17
1979	2,312.00	6,178.67	2.67	2,291.75	4,714.92	2,404.92
1980	2,262.25	6,824.42	2.58	2,369.42	4,722.33	2,348.25
1981	2,002.75	6,349.75	2.75	2,390.58	4,685.67	2,208.50
1982	2,114.67	6,983.42	2.75	2,405.58	4,705.25	2,212.33

Source: Monthly averages for each year were calculated by the Energy Information Administration, Electric Power Division, based on monthly data from PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C8. Capacity Utilization Ratios for Fossil-Fuel Steam in the New York Region, 1972-1982

Year	Coal	Oil	Gas
1972	0.2987	0.5389	0.1966
1973	0.3039	0.5450	0.1654
1974	0.3350	0.4828	0.0931
1975	0.3223	0.5335	0.0397
1976	0.3149	0.5071	0.0180
1977	0.3457	0.4835	0.0134
1978	0.3225	0.4894	0.0041
1979	0.3177	0.3782	0.2596
1980	0.3205	0.3330	0.4416
1981	0.3410	0.3343	0.5154
1982	0.3572	0.2963	0.6584

Note: Capacity utilization ratios for each fuel were calculated by Energy Information Administration, Electric Power Division, by taking the ratio of actual generation for the year to the potential generation based on the highest reported monthly available capacity for the year.

Sources: •Generation data: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms. •Capacity data: PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C9. Net Generation of Electricity in the MAAC Region, 1972-1982 (Gigawatthours)

Year	Total[a]	Coal	Share (%)	Oil	Share (%)	Gas	Share (%)	Nuclear	Share (%)	Hydro-electric	Share (%)
1972	133,930	72,381	54	50,614	38	2,703	2	4,458	3	3,774	3
1973	140,563	83,017	59	47,863	34	2,458	2	3,762	3	3,463	2
1974	138,084	77,163	56	45,017	33	1,931	1	10,652	8	3,321	2
1975	137,250	78,065	57	30,864	22	1,052	1	23,405	17	3,864	3
1976	145,547	81,286	56	33,267	23	1,203	1	26,230	18	3,561	2
1977	154,576	77,173	50	40,574	26	782	1	32,710	21	3,337	2
1978	163,512	79,441	49	43,718	27	259	*	37,517	23	2,577	2
1979	158,602	86,274	54	32,411	20	3,436	2	33,059	21	3,422	2
1980	161,979	92,913	57	28,850	18	8,106	5	30,055	19	2,056	1
1981	153,789	87,715	57	23,257	15	8,276	5	32,486	21	2,054	1
1982	154,936	89,858	58	17,480	11	6,446	4	37,967	25	3,185	2

[a]Total includes generation from refuse and wood.
*=Less than 0.5 percent.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Appendix C

Table C10. Fossil-Fuel Costs for Electric Generation in the MAAC Region, 1972-1982 (Dollars per Million Btu)

Year	Weighted Average[a]	Coal[b]	Oil[c]	Gas[d]
1972	0.54	0.46	0.64	0.50
1973	0.64	0.51	0.83	0.54
1974	1.37	0.95	2.03	0.85
1975	1.39	1.07	2.05	0.96
1976	1.38	1.08	1.98	1.39
1977	1.57	1.13	2.32	1.79
1978	1.67	1.28	2.21	1.89
1979	1.96	1.32	3.33	2.42
1980	2.29	1.40	4.66	3.03
1981	2.58	1.62	5.58	3.93
1982	2.41	1.73	5.13	4.28

[a]Quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plants.

[b]Includes anthracite, bituminous coal, subbituminous coal, and lignite.

[c]Includes fuel oil Nos. 2, 4, 5, and 6 as well as crude oil, topped crude, kerosene, and jet fuel.

[d]Includes natural gas, coke oven gas, blast furnace gas, and refinery gas.

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Appendix C

Table C11. Monthly Average Available Fossil Fuel Steam Capacity by Fuel in the MAAC Region, 1972-1982 (Megawatts)

	Capacity					
	Single Fuel			Multifuel		
Year	Coal	Oil	Gas	Coal	Oil	Gas
1972	9,198.83	3,536.67	0	5,785.83	7,430.83	3,325.17
1973	9,464.58	3,635.25	0	6,193.75	6,721.08	2,876.75
1974	8,732.33	3,658.50	0	6,037.42	7,183.08	3,305.67
1975	8,707.00	5,479.67	0	4,669.58	6,045.83	3,704.42
1976	8,953.50	5,895.75	0	4,272.50	5,901.25	3,492.17
1977	8,526.67	6,310.83	0	4,455.08	6,077.08	3,288.25
1978	9,059.83	5,988.50	0	4,883.67	6,413.17	2,665.92
1979	8,890.25	5,536.33	0	4,869.42	7,396.25	3,301.33
1980	10,096.17	6,303.42	0	4,091.67	5,471.75	2,514.67
1981	9,501.17	5,088.33	0	4,852.50	7,217.58	3,123.00
1982	9,644.50	4,189.58	0	6,082.58	8,115.92	3,684.67

Source: Monthly averages for each year were calculated by the Energy Information Administration, Electric Power Division, based on monthly data from PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C12. Capacity Utilization Ratios for Fossil-Fuel Steam in the MAAC Region, 1972-1982

Year	Coal	Oil	Gas
1972	0.5516	0.5251	0.1089
1973	0.5654	0.5002	0.0662
1974	0.5559	0.4476	0.0403
1975	0.6166	0.3033	0.0262
1976	0.6520	0.3144	0.0334
1977	0.6314	0.3499	0.0221
1978	0.5886	0.3664	0.0080
1979	0.6940	0.2943	0.1000
1980	0.6654	0.2268	0.2700
1981	0.6347	0.1811	0.2174
1982	0.5954	0.1425	0.1519

Note: Capacity utilization ratios for each fuel were calculated by Energy Information Administration, Electric Power Division, by taking the ratio of actual generation for the year to the potential generation based on the highest reported monthly available capacity for the year.

Sources: •Generation data: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms. •Capacity data: PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C13. Net Generation of Electricity in the Southeast Region, 1972-1982 (Gigawatthours)

Year	Total[a]	Coal	Share (%)	Oil	Share (%)	Gas	Share (%)	Nuclear	Share (%)	Hydro-electric	Share (%)
1972	275,866	196,593	71	23,374	8	12,121	4	5,277	2	38,501	14
1973	306,163	214,377	70	26,571	9	9,447	3	13,338	4	42,431	14
1974	298,789	199,449	67	28,890	10	7,615	3	23,342	8	39,493	13
1975	302,967	194,340	64	22,682	7	6,871	2	35,648	12	43,426	14
1976	325,360	226,031	69	25,034	8	2,472	1	36,450	11	35,374	11
1977	349,513	226,853	65	28,138	8	2,780	1	55,619	16	36,124	10
1978	353,459	218,324	62	28,839	8	3,241	1	70,580	20	32,475	9
1979	361,701	236,256	65	18,313	5	3,175	1	59,271	16	44,686	12
1980	376,060	261,532	70	11,032	3	2,476	1	67,097	18	33,922	9
1981	372,133	266,622	72	5,924	2	1,967	1	76,973	21	20,647	6
1982	369,077	246,000	67	2,687	1	1,048	*	84,114	23	35,227	10

[a]Total includes generation from refuse and wood.
*=Less than 0.5 percent.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Appendix C

Table C14. Fossil-Fuel Costs for Electric Generation in the Southeast Region, 1972-1982 (Dollars per Million Btu)

Year	Weighted Average[a]	Coal[b]	Oil[c]	Gas[d]
1972	0.39	0.38	0.49	0.35
1973	0.44	0.42	0.61	0.44
1974	0.89	0.79	1.64	0.61
1975	1.01	0.92	1.84	0.81
1976	1.08	0.97	1.89	1.21
1977	1.26	1.11	2.25	1.38
1978	1.40	1.29	2.16	1.64
1979	1.54	1.41	3.01	2.04
1980	1.69	1.56	4.13	2.38
1981	1.87	1.78	5.53	3.00
1982	1.93	1.89	5.49	3.71

[a]Quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plants.
[b]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[c]Includes fuel oil Nos. 2, 4, 5, and 6 as well as crude oil, topped crude, kerosene, and jet fuel.
[d]Includes natural gas, coke oven gas, blast furnace gas, and refinery gas.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Appendix C

Table C15. Monthly Average Available Fossil Fuel Steam Capacity by Fuel in the Southeast Region, 1972-1982 (Megawatts)

	Capacity					
	Single Fuel			Multifuel		
Year	Coal	Oil	Gas	Coal	Oil	Gas
1972	25,007.17	181.33	0	7,038.83	4,323.67	5,897.33
1973	26,700.75	441.25	0	7,111.83	3,980.17	5,980.08
1974	28,062.67	1,046.08	0	7,141.25	3,994.33	6,218.08
1975	28,482.25	1,596.50	0	6,983.67	3,943.25	6,038.50
1976	29,644.92	1,829.67	0	6,916.17	3,909.92	5,974.17
1977	30,235.42	1,855.92	26.00	6,990.00	4,018.67	5,876.92
1978	31,767.75	1,885.17	27.83	6,415.83	4,416.67	4,485.25
1979	31,976.92	1,903.33	0	7,229.00	4,261.50	5,889.17
1980	33,995.42	1,985.42	0	6,568.75	4,311.17	5,199.92
1981	35,698.83	2,116.83	0	6,961.42	4,683.42	5,360.00
1982	36,717.08	1,317.92	0	7,122.50	5,452.33	6,133.50

Source: Monthly averages for each year were calculated by the Energy Information Administration, Electric Power Division, based on monthly data from PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C16. Capacity Utilization Ratios for Fossil-Fuel Steam in the Southeast Region, 1972-1982

Year	Coal	Oil	Gas
1972	0.7422	0.5603	0.1987
1973	0.6834	0.5636	0.1384
1974	0.6225	0.5403	0.1128
1975	0.6049	0.3997	0.1150
1976	0.6906	0.4222	0.0393
1977	0.6762	0.4266	0.0448
1978	0.6382	0.4313	0.0690
1979	0.6713	0.3104	0.0483
1980	0.7095	0.1829	0.0380
1981	0.6927	0.0906	0.0284
1982	0.6321	0.0437	0.0137

Note: Capacity utilization ratios for each fuel were calculated by Energy Information Administration, Electric Power Division, by taking the ratio of actual generation for the year to the potential generation based on the highest reported monthly available capacity for the year.

Sources: •Generation data: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms. •Capacity data: PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C17. Net Generation of Electricity in the Florida Region, 1972-1982 (Gigawatthours)

Year	Total[a]	Coal	Share (%)	Oil	Share (%)	Gas	Share (%)	Nuclear	Share (%)	Hydro-electric	Share (%)
1972	62,252	7,113	11	40,229	65	14,606	23	66	*	238	*
1973	69,839	8,582	12	42,039	60	14,303	20	4,681	7	234	*
1974	69,403	8,105	12	39,704	57	13,465	19	7,877	11	251	*
1975	72,207	7,823	11	43,914	61	11,866	16	8,370	12	234	*
1976	74,730	7,463	10	47,618	64	10,742	14	8,648	12	259	*
1977	80,985	9,967	12	41,383	51	11,835	15	17,557	22	243	*
1978	85,854	10,365	12	45,845	53	13,606	16	15,810	18	228	*
1979	87,363	12,237	14	45,047	52	14,446	17	15,391	18	241	*
1980	89,752	13,967	16	44,335	49	14,499	16	16,737	19	215	*
1981	92,233	14,466	16	47,428	51	15,698	17	14,461	16	180	*
1982	86,701	16,396	19	33,846	39	16,879	19	19,319	22	261	*

aTotal includes generation from refuse and wood.

*=Less than 0.5 percent.

Note: Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Appendix C

Table C18. Fossil-Fuel Costs for Electric Generation in the Florida Region, 1972-1982 (Dollars per Million Btu)

Year	Weighted Average[a]	Coal[b]	Oil[c]	Gas[d]
1972	0.46	0.39	0.49	0.42
1973	0.61	0.50	0.68	0.45
1974	1.37	0.69	1.80	0.59
1975	1.53	0.98	1.88	0.69
1976	1.59	1.18	1.85	0.80
1977	1.78	1.33	2.15	0.85
1978	1.74	1.51	2.02	1.00
1979	2.39	1.64	2.97	1.25
1980	2.97	1.80	3.79	1.51
1981	3.66	2.06	4.80	1.84
1982	3.23	2.18	4.33	2.19

[a]Quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plants.
[b]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[c]Includes fuel oil Nos. 2, 4, 5, and 6 as well as crude oil, topped crude, kerosene, and jet fuel.
[d]Includes natural gas, coke oven gas, blast furnace gas, and refinery gas.

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Appendix C

Table C19. Monthly Average Available Fossil-Fuel Steam Capacity by Fuel in the Florida Region, 1972-1982 (Megawatts)

	Capacity					
	Single Fuel			Multifuel		
Year	Coal	Oil	Gas	Coal	Oil	Gas
1972	1,058.17	7,987.50	0	0	100.17	115.33
1973	1,237.92	8,240.25	0	0	99.67	115.17
1974	1,296.50	8,764.50	0	0	99.67	115.17
1975	1,219.67	8,983.92	0	0	57.75	66.75
1976	1,350.17	9,225.25	0	0	57.75	65.92
1977	1,444.83	10,148.25	0	0	57.67	66.58
1978	1,471.67	5,799.50	0	0	5,671.67	5,843.58
1979	1,630.50	5,571.25	0	0	5,580.17	5,760.67
1980	1,817.08	5,556.50	0	0	5,586.33	5,783.67
1981	2,075.08	6,566.67	0	0	5,797.17	5,984.83
1982	2,595.08	6,553.92	0	159.75	5,920.67	5,954.83

Source: Monthly averages for each year were calculated by the Energy Information Administration, Electric Power Division, based on monthly data from PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C20. Capacity Utilization Ratios for Fossil-Fuel Steam in the Florida Region, 1972-1982

Year	Coal	Oil	Gas
1972	0.7899	0.5796	(a)
1973	0.6865	0.5306	(a)
1974	0.6739	0.4567	(a)
1975	0.6912	0.4999	(a)
1976	0.5612	0.5071	(a)
1977	0.7422	0.4056	(a)
1978	0.7714	0.4164	0.2382
1979	0.7671	0.4161	0.2525
1980	0.8268	0.4097	0.2506
1981	0.7575	0.4050	0.2752
1982	0.6524	0.2932	0.3004

[a]Gas capacity utilization ratios for 1972 through 1977 were not calculated because of error in gas-fired capacity data.

Note: Capacity utilization ratios for each fuel were calculated by Energy Information Administration, Electric Power Division, by taking the ratio of actual generation for the year to the potential generation based on the highest reported monthly available capacity for the year.

Sources: •Generation data: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms. •Capacity data: PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C21. Net Generation of Electricity in the ECAR Region, 1972-1982 (Gigawatthours)

Year	Total[a]	Coal	Share (%)	Oil	Share (%)	Gas	Share (%)	Nuclear	Share (%)	Hydro-electric	Share (%)
1972	315,492	294,943	93	7,298	2	8,180	3	2,311	1	2,756	1
1973	338,376	317,559	94	9,320	3	6,348	2	3,165	1	1,981	1
1974	335,369	312,105	93	13,551	4	7,157	2	436	*	2,117	1
1975	347,442	321,394	93	11,877	3	4,893	1	7,172	2	2,106	1
1976	372,376	344,062	92	12,351	3	3,601	1	10,371	3	1,991	1
1977	377,392	346,481	92	13,527	4	2,013	1	13,651	4	1,719	*
1978	373,107	331,431	89	18,891	5	2,493	1	18,406	5	1,885	1
1979	399,228	361,623	91	12,186	3	2,807	1	20,324	5	2,288	1
1980	397,043	366,280	92	7,837	2	2,353	1	18,621	5	1,951	*
1981	404,004	369,098	91	4,716	1	1,914	*	26,460	7	1,816	*
1982	379,016	352,241	93	2,471	1	1,222	*	21,119	6	1,962	1

[a]Total includes generation from refuse and wood.
*=Less than 0.5 percent.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Appendix C

Table C22. Fossil-Fuel Costs for Electric Generation in the ECAR Region, 1971-1982 (Dollars per Million Btu)

Year	Weighted Average[a]	Coal[b]	Oil[c]	Gas[d]
1972	0.36	0.35	0.73	0.50
1973	0.40	0.39	0.83	0.56
1974	0.81	0.76	1.96	0.83
1975	0.90	0.84	2.15	1.19
1976	0.93	0.87	2.29	1.54
1977	1.04	0.97	2.63	1.82
1978	1.28	1.19	2.67	1.93
1979	1.34	1.27	3.37	2.29
1980	1.48	1.40	4.57	2.71
1981	1.67	1.60	6.20	3.13
1982	1.73	1.70	6.08	3.73

[a]Quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plants.
[b]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[c]Includes fuel oil Nos. 2, 4, 5, and 6 as well as crude oil, topped crude, kerosene, and jet fuel.
[d]Includes natural gas, coke oven gas, blast furnace gas, and refinery gas.

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Appendix C

Table C23. Monthly Average Available Fossil Fuel Steam Capacity by Fuel in the ECAR Region, 1972-1982 (Megawatts)

	Capacity					
	Single Fuel			Multifuel		
Year	Coal	Oil	Gas	Coal	Oil	Gas
1972	44,515.67	1,941.00	331.00	2,856.33	1,547.17	2,760.33
1973	43,474.33	2,065.17	296.58	2,723.42	1,622.00	2,843.42
1974	47,335.33	2,290.00	249.83	2,725.25	1,654.33	2,903.17
1975	43,626.92	2,531.83	254.67	3,131.17	3,190.92	1,803.08
1976	44,364.50	2,677.92	95.42	1,798.00	1,942.50	1,673.50
1977	43,663.08	3,458.17	75.33	1,653.67	1,915.50	1,532.58
1978	46,596.67	3,530.00	82.92	1,853.33	2,173.17	1,540.58
1979	48,383.92	3,830.75	7.08	1,794.00	2,162.75	1,468.83
1980	50,544.75	3,886.58	7.17	1,741.08	2,113.58	1,500.08
1981	52,737.33	3,684.50	7.08	2,068.33	1,747.75	1,797.17
1982	54,709.00	3,092.67	7.08	2,086.25	1,856.83	1,800.00

Source: Monthly averages for each year were calculated by the Energy Information Administration, Electric Power Division, based on monthly data from PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C24. Capacity Utilization Ratios for Fossil-Fuel Steam in the ECAR Region, 1972-1982

Year	Coal	Oil	Gas
1972	0.6852	0.1955	0.1806
1973	0.7023	0.2378	0.1397
1974	0.6471	0.2924	0.1564
1975	0.6801	0.1702	0.1717
1976	0.7621	0.2172	0.1218
1977	0.7848	0.2075	0.0566
1978	0.7196	0.3000	0.0779
1979	0.7684	0.1849	0.1133
1980	0.7286	0.1262	0.0847
1981	0.7227	0.0835	0.0751
1982	0.6516	0.0489	0.0465

Note: Capacity utilization ratios for each fuel were calculated by Energy Information Administration, Electric Power Division, by taking the ratio of actual generation for the year to the potential generation based on the highest reported monthly available capacity for the year.

Sources: •Generation data: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms. •Capacity data: PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C25. Net Generation of Electricity in the MAIN Region, 1972-1982 (Gigawatthours)

Year	Total[a]	Coal	Share (%)	Oil	Share (%)	Gas	Share (%)	Nuclear	Share (%)	Hydro-electric	Share (%)
1972	129,724	96,319	74	6,745	5	8,425	6	16,121	12	2,114	2
1973	146,521	106,728	73	5,873	4	5,402	4	25,804	18	2,713	2
1974	145,548	103,976	71	5,639	4	6,150	4	27,534	19	2,249	2
1975	152,627	108,440	71	5,555	4	4,283	3	32,345	21	2,004	1
1976	162,269	114,964	71	5,511	3	3,304	2	37,004	23	1,485	1
1977	168,615	119,019	71	7,302	4	1,421	1	39,403	23	1,471	1
1978	176,126	117,522	67	9,609	5	2,439	1	44,469	25	2,067	1
1979	177,107	124,613	70	8,668	5	3,903	2	37,665	21	2,226	1
1980	174,537	125,412	72	7,532	4	2,231	1	37,439	21	1,902	1
1981	162,115	114,054	70	5,585	3	1,311	1	38,961	24	2,195	1
1982	156,373	110,929	71	4,216	3	1,008	1	37,756	24	2,456	2

[a]Total includes generation from refuse and wood.

Note: Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Appendix C

Table C26. Fossil-Fuel Costs for Electric Generation in the MAIN Region, 1972-1982 (Dollars per Million Btu)

Year	Weighted Average[a]	Coal[b]	Oil[c]	Gas[d]
1972	0.41	0.39	0.63	0.49
1973	0.44	0.42	0.74	0.54
1974	0.63	0.58	1.55	0.69
1975	0.81	0.74	1.78	1.03
1976	0.91	0.83	2.23	1.32
1977	1.11	0.97	2.57	1.79
1978	1.36	1.21	2.63	2.51
1979	1.57	1.37	3.85	2.54
1980	1.78	1.50	5.59	3.08
1981	2.05	1.70	7.26	3.97
1982	2.08	1.81	6.98	4.44

[a]Quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plants.

[b]Includes anthracite, bituminous coal, subbituminous coal, and lignite.

[c]Includes fuel oil Nos. 2, 4, 5, and 6 as well as crude oil, topped crude, kerosene, and jet fuel.

[d]Includes natural gas, coke oven gas, blast furnace gas, and refinery gas.

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Appendix C

Table C27. Monthly Average Available Fossil Fuel Steam Capacity by Fuel in the MAIN Region, 1972-1982 (Megawatts)

Year	Capacity					
	Single Fuel			Multifuel		
	Coal	Oil	Gas	Coal	Oil	Gas
1972	15,556.83	1,091.33	264.50	4,299.83	914.33	5,291.50
1973	14,245.42	574.33	264.75	4,585.00	1,499.58	6,279.58
1974	13,528.33	450.92	296.08	4,535.75	1,339.25	5,673.42
1975	15,549.33	511.92	118.08	4,004.08	986.25	5,212.75
1976	18,863.67	1,130.25	19.17	2,494.83	219.08	2,984.25
1977	20,151.83	1,616.50	19.08	1,882.50	282.67	2,382.08
1978	20,575.75	2,334.58	19.25	1,920.08	398.58	2,561.83
1979	21,124.42	3,170.50	19.25	1,865.25	556.50	2,683.58
1980	20,225.92	2,734.83	0	1,240.83	985.58	2,490.33
1981	20,312.00	2,705.42	0	1,241.75	972.08	2,482.50
1982	21,029.08	2,427.58	0	1,237.50	687.33	2,154.00

Source: Monthly averages for each year were calculated by the Energy Information Administration, Electric Power Division, based on monthly data from PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C28. Capacity Utilization Ratios for Fossil-Fuel Steam in the MAIN Region, 1972-1982

Year	Coal	Oil	Gas
1972	0.5294	0.2240	0.1456
1973	0.5748	0.2147	0.0546
1974	0.5851	0.2094	0.0757
1975	0.5497	0.2578	0.0654
1976	0.5290	0.2954	0.0866
1977	0.5300	0.2502	0.0341
1978	0.5035	0.2623	0.0735
1979	0.5199	0.1951	0.1128
1980	0.5672	0.2009	0.0576
1981	0.5363	0.1494	0.0309
1982	0.5130	0.1342	0.0297

Note: Capacity utilization ratios for each fuel were calculated by Energy Information Administration, Electric Power Division, by taking the ratio of actual generation for the year to the potential generation based on the highest reported monthly available capacity for the year.

Sources: •Generation data: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms. •Capacity data: PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C29. Net Generation of Electricity in the MAPP Region, 1972-1982 (Gigawatthours)

Year	Total[a]	Coal	Share (%)	Oil	Share (%)	Gas	Share (%)	Nuclear	Share (%)	Hydro-electric	Share (%)
1972	78,311	34,137	44	8,406	11	14,620	19	3,798	5	17,284	22
1973	78,371	35,399	45	9,996	13	15,479	20	4,071	5	13,360	17
1974	84,154	35,614	42	10,542	13	13,534	16	10,002	12	14,422	17
1975	86,781	34,765	40	6,981	8	9,125	11	18,220	21	17,647	20
1976	93,598	47,134	50	7,096	8	4,889	5	18,386	20	16,056	17
1977	97,531	54,130	56	6,829	7	2,875	3	21,592	22	12,080	12
1978	102,804	55,412	54	8,449	8	1,837	2	20,700	20	16,396	16
1979	105,577	58,229	55	6,067	6	2,960	3	23,252	22	15,064	14
1980	101,758	66,270	65	531	1	2,150	2	18,586	18	14,148	14
1981	101,506	67,901	67	262	*	1,127	1	18,619	18	13,531	13
1982	102,283	65,746	64	215	*	489	*	21,356	21	14,386	14

[a]Total includes generation from refuse and wood.
*=Less than 0.5 percent.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Appendix C

Table C30. Fossil-Fuel Costs for Electric Generation in the MAPP Region, 1972-1982 (Dollars per Million Btu)

Year	Weighted Average[a]	Coal[b]	Oil[c]	Gas[d]
1972	0.38	0.37	0.76	0.34
1973	0.41	0.39	0.90	0.42
1974	0.53	0.50	1.80	0.49
1975	0.72	0.67	2.03	0.65
1976	0.76	0.70	1.94	0.87
1977	0.88	0.80	2.29	1.14
1978	0.95	0.88	2.23	1.35
1979	1.08	0.99	3.39	1.70
1980	1.14	1.06	5.12	2.02
1981	1.18	1.14	7.08	2.62
1982	1.28	1.25	6.59	3.37

[a]Quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plants.
[b]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[c]Includes fuel oil Nos. 2, 4, 5, and 6 as well as crude oil, topped crude, kerosene, and jet fuel.
[d]Includes natural gas, coke oven gas, blast furnace gas, and refinery gas.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Appendix C

Table C31. Monthly Average Available Fossil Fuel Steam Capacity by Fuel in the MAPP Region, 1972-1982 (Megawatts)

	Capacity					
	Single Fuel			Multifuel		
Year	Coal	Oil	Gas	Coal	Oil	Gas
1972	3,948.50	201.83	93.17	3,976.33	1,653.50	3,862.33
1973	3,785.58	191.33	89.83	3,949.33	1,574.58	3,798.25
1974	3,803.08	191.33	86.83	3,897.83	1,604.00	3,785.50
1975	4,838.58	183.42	58.17	3,672.00	1,551.75	3,469.17
1976	4,888.50	183.83	29.25	3,653.75	1,555.42	3,445.92
1977	6,186.08	197.25	41.92	3,299.92	1,027.00	3,527.17
1978	7,830.33	243.00	31.33	3,302.42	976.67	3,471.83
1979	8,835.58	250.92	32.50	2,544.58	982.08	2,691.67
1980	10,300.92	240.75	32.42	2,451.42	918.67	2,658.08
1981	12,451.83	225.00	32.33	2,438.50	917.42	2,679.25
1982	12,101.67	117.25	0	2,327.50	856.92	2,529.17

Source: Monthly averages for each year were calculated by the Energy Information Administration, Electric Power Division, based on monthly data from PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C32. Capacity Utilization Ratios for Fossil-Fuel Steam in the MAPP Region, 1972-1982

Year	Coal	Oil	Gas
1972	0.4177	0.0520	0.3933
1973	0.4417	0.0595	0.3483
1974	0.4544	0.0499	0.2957
1975	0.3918	0.0608	0.2290
1976	0.5368	0.0733	0.1218
1977	0.5657	0.1001	0.0700
1978	0.5120	0.1174	0.0442
1979	0.5048	0.0746	0.0755
1980	0.5346	0.0399	0.0670
1981	0.5084	0.0228	0.0316
1982	0.4941	0.0205	0.0159

Note: Capacity utilization ratios for each fuel were calculated by Energy Information Administration, Electric Power Division, by taking the ratio of actual generation for the year to the potential generation based on the highest reported monthly available capacity for the year.

Sources: •Generation data: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms. •Capacity data: PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C33. Net Generation of Electricity in the SPP Region, 1972-1982 (Gigawatthours)

Year	Total[a]	Coal	Share (%)	Oil	Share (%)	Gas	Share (%)	Nuclear	Share (%)	Hydro-electric	Share (%)
1972	140,631	6,998	5	5,552	4	124,124	88	0	0	3,855	3
1973	146,173	7,493	5	11,591	8	116,676	80	0	0	10,313	7
1974	150,398	9,184	6	13,605	9	117,428	78	361	*	9,724	6
1975	153,984	11,835	8	14,149	9	114,842	75	4,881	3	8,188	5
1976	163,399	13,792	8	23,042	14	117,968	72	3,866	2	4,633	3
1977	180,088	21,197	12	33,731	19	115,698	64	5,099	3	4,268	2
1978	196,294	31,507	16	36,364	19	117,941	60	5,234	3	5,153	3
1979	188,448	35,417	19	20,789	11	121,135	64	3,918	2	7,103	4
1980	201,446	51,135	25	10,778	5	127,820	63	7,833	4	3,801	2
1981	212,360	76,633	36	5,236	2	118,413	56	9,075	4	2,929	1
1982	206,774	87,997	43	1,665	1	103,979	50	7,482	4	5,590	3

a/Total includes generation from refuse and wood.
*=Less than 0.5 percent.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Appendix C

Table C34. Fossil-Fuel Costs for Electric Generation in the SPP Region, 1972-1982 (Dollars per Million Btu)

Year	Weighted Average[a]	Coal[b]	Oil[c]	Gas[d]
1972	0.29	0.29	0.68	0.26
1973	0.35	0.33	0.92	0.29
1974	0.53	0.39	1.91	0.38
1975	0.68	0.56	1.77	0.56
1976	0.92	0.65	1.80	0.81
1977	1.14	0.77	1.96	1.01
1978	1.25	0.93	1.91	1.17
1979	1.45	1.06	2.56	1.43
1980	1.64	1.24	3.51	1.73
1981	1.89	1.44	4.56	2.09
1982	2.05	1.60	4.67	2.39

[a]Quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plants.

[b]Includes anthracite, bituminous coal, subbituminous coal, and lignite.

[c]Includes fuel oil Nos. 2, 4, 5, 6 as well as crude oil, topped crude, kerosene and jet fuel.

[d]Includes natural gas, coke oven gas, blast furnace gas, and refinery gas.

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Appendix C

Table C35. Monthly Average Available Fossil Fuel Steam Capacity by Fuel in the SPP Region, 1972-1982 (Megawatts)

Year	Capacity					
	Single Fuel			Multifuel		
	Coal	Oil	Gas	Coal	Oil	Gas
1972	3,208.50	41.33	3,052.33	1,545.33	18,610.17	22,978.67
1973	3,353.08	445.50	2,857.25	1,430.83	18,449.58	22,680.50
1974	3,352.67	411.25	3,228.33	1,053.75	20,689.83	23,199.17
1975	3,380.67	396.75	3,136.50	1,042.92	23,226.33	24,869.42
1976	3,465.50	282.33	3,049.83	1,123.42	23,784.92	25,549.58
1977	4,283.17	1,229.33	3,391.83	1,344.25	22,440.33	24,334.75
1978	6,123.92	1,210.08	2,869.67	1,497.25	21,878.00	24,021.08
1979	6,652.00	0	3,037.75	2,009.67	21,945.83	23,922.75
1980	8,333.25	774.92	2,980.92	3,074.92	23,112.92	25,344.83
1981	10,095.08	0	2,930.75	3,839.58	23,747.75	25,619.50
1982	11,804.42	0	2,693.92	3,889.42	23,976.83	25,911.75

Source: Monthly averages for each year were calculated by the Energy Information Administration, Electric Power Division, based on monthly data from PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C36. Capacity Utilization Ratios for Fossil-Fuel Steam in the SPP Region, 1972-1982

Year	Coal	Oil	Gas
1972	0.3106	0.0411	0.5178
1973	0.3346	0.0595	0.4448
1974	0.3778	0.0594	0.4199
1975	0.4371	0.0536	0.3796
1976	0.4521	0.0895	0.3856
1977	0.4916	0.1396	0.3989
1978	0.4776	0.1539	0.4156
1979	0.5142	0.0941	0.4297
1980	0.4985	0.0444	0.4292
1981	0.5360	0.0216	0.3975
1982	0.5409	0.0064	0.3412

Note: Capacity utilization ratios for each fuel were calculated by Energy Information Administration, Electric Power Division, by taking the ratio of actual generation for the year to the potential generation based on the highest reported monthly available capacity for the year.

Sources: •Generation data: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms. •Capacity data: PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C37. Net Generation of Electricity in the ERCOT Region, 1972-1982 (Gigawatthours)

Year	Total[a]	Coal	Share (%)	Oil	Share (%)	Gas	Share (%)	Nuclear	Share (%)	Hydro-electric	Share (%)
1972	103,397	2,379	2	930	1	99,641	96	0	0	446	*
1973	108,506	6,527	6	3,406	3	98,002	90	0	0	571	1
1974	112,462	6,867	6	2,773	2	102,009	91	0	0	814	1
1975	116,576	11,421	10	584	1	103,651	89	0	0	920	1
1976	122,657	14,946	12	1,521	1	105,592	86	0	0	598	*
1977	137,074	18,093	13	1,995	1	116,272	85	0	0	714	1
1978	147,804	27,374	19	3,215	2	116,750	79	0	0	466	*
1979	150,344	39,893	27	2,428	2	107,526	72	0	0	496	*
1980	162,226	52,440	32	882	1	108,351	67	0	0	553	*
1981	164,868	59,687	36	681	*	103,717	63	0	0	782	*
1982	165,343	65,069	39	992	1	98,669	60	0	0	613	*

[a]Total includes generation from refuse and wood.
*=Less than 0.5 percent.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Appendix C

Table C38. Fossil-Fuel Costs for Electric Generation in the ERCOT Region, 1972-1982 (Dollars per Million Btu)

Year	Weighted Average[a]	Coal[b]	Oil[c]	Gas[d]
1972	0.24	0.21	0.84	0.23
1973	0.30	0.13	1.01	0.28
1974	0.51	0.17	1.69	0.48
1975	0.81	0.23	1.95	0.85
1976	1.03	0.31	1.96	1.12
1977	1.21	0.51	2.10	1.33
1978	1.33	0.59	1.99	1.49
1979	1.50	0.92	2.68	1.71
1980	1.76	1.18	3.75	2.04
1981	2.32	1.44	4.43	2.83
1982	2.81	1.56	4.79	3.60

[a]Quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plants.
[b]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[c]Includes fuel oil Nos. 2, 4, 5, and 6 as well as crude oil, topped crude, kerosene, and jet fuel.
[d]Includes natural gas, coke oven gas, blast furnace gas, and refinery gas.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Appendix C

Table C39. Monthly Average Available Fossil Fuel Steam Capacity by Fuel in the ERCOT Region, 1972-1982 (Megawatts)

	Capacity					
	Single Fuel			Multifuel		
Year	Coal	Oil	Gas	Coal	Oil	Gas
1972	538.17	0	7747.17	0	15,241.33	15,686.17
1973	839.92	0	4944.08	0	17,288.17	17,811.08
1974	804.00	0	4363.92	0	19,253.42	19,788.67
1975	1,170.33	0	4,171.08	0	20,246.42	20,928.83
1976	1,518.50	0	2,108.00	0	23,868.83	24,562.58
1977	1,834.00	0	2,962.08	248.58	24,048.67	24,523.92
1978	2,633.25	0	2,962.17	921.25	24,590.92	25,226.25
1979	3,891.50	0	2,953.00	1,494.00	24,749.75	25,864.17
1980	5,578.42	0	2,419.17	1,075.83	24,831.25	25,347.75
1981	6,433.08	0	2,485.17	1,107.08	25,231.33	25,362.75
1982	6,777.17	0	2,480.08	1,085.83	25,204.00	25,741.17

Source: Monthly averages for each year were calculated by the Energy Information Administration, Electric Power Division, based on monthly data from PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C40. Capacity Utilization Ratios for Fossil-Fuel Steam in the ERCOT Region, 1972-1982

Year	Coal	Oil	Gas
1972	0.2824	0.0098	0.4685
1973	0.7595	0.0192	0.4212
1974	0.7360	0.0129	0.4014
1975	0.8985	0.0026	0.3880
1976	0.9570	0.0060	0.3758
1977	0.7042	0.0078	0.4082
1978	0.6853	0.0127	0.3948
1979	0.7136	0.0092	0.3479
1980	0.7639	0.0033	0.3685
1981	0.7740	0.0025	0.3445
1982	0.8493	0.0039	0.3425

Note: Capacity utilization ratios for each fuel were calculated by Energy Information Administration, Electric Power Division, by taking the ratio of actual generation for the year to the potential generation based on the highest reported monthly available capacity for the year.

Sources: •Generation data: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms. •Capacity data: PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C41. Net Generation of Electricity in the Pacific Northwest Region, 1972-1982 (Gigawatthours)

Year	Total[a]	Coal	Share (%)	Oil	Share (%)	Gas	Share (%)	Nuclear	Share (%)	Hydro-electric	Share (%)
1972	162,150	22,030	14	989	1	5,541	3	2,919	2	130,561	81
1973	154,043	29,296	19	791	1	5,034	3	4,432	3	114,378	74
1974	178,136	28,945	16	508	*	5,600	3	3,889	2	139,130	78
1975	183,872	35,679	19	837	*	4,596	2	3,310	2	139,436	76
1976	204,988	42,858	21	632	*	3,737	2	4,556	2	153,121	75
1977	175,924	53,492	30	693	*	3,317	2	11,032	6	107,085	61
1978	205,418	52,638	26	675	*	2,948	1	6,313	3	142,661	69
1979	204,242	60,294	30	1,465	1	3,907	2	8,335	4	129,981	64
1980	209,764	63,520	30	465	*	3,346	2	8,103	4	134,152	64
1981	230,626	72,254	31	241	*	1,470	1	9,228	4	147,278	64
1982	236,644	70,235	30	193	*	661	*	8,992	4	156,495	66

[a]Total includes generation from refuse and wood.
*=Less than 0.5 percent.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Appendix C

Table C42. Fossil-fuel Costs for Electric Generation in the Pacific Northwest Region, 1972-1982 (Dollars per Million Btu)

Year	Weighted Average[a]	Coal[b]	Oil[c]	Gas[d]
1972	0.25	0.23	0.45	0.29
1973	0.31	0.28	0.83	0.34
1974	0.38	0.32	2.08	0.43
1975	0.49	0.41	2.14	0.59
1976	0.51	0.45	2.04	0.80
1977	0.58	0.51	2.32	1.08
1978	0.63	0.57	2.47	1.32
1979	0.84	0.67	4.64	2.00
1980	0.94	0.79	5.33	2.82
1981	0.96	0.90	6.57	3.25
1982	1.07	1.04	6.41	3.29

[a]Quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plants.
[b]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[c]Includes fuel oil Nos. 2, 4, 5, and 6 as well as crude oil, topped crude, kerosene, and jet fuel.
[d]Includes natural gas, coke oven gas, blast furnace gas, and refinery gas.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Appendix C

Table C43. Monthly Average Available Fossil Fuel Steam Capacity by Fuel in the Pacific Northwest Region, 1972-1982 (Megawatts)

	Capacity					
	Single Fuel			Multifuel		
Year	Coal	Oil	Gas	Coal	Oil	Gas
1972	4,007.50	277.17	0	1,669.83	746.67	2,490.17
1973	4,441.67	244.25	0	1,552.83	683.00	2,383.83
1974	6,017.67	227.33	0	1,653.17	673.83	2,450.00
1975	6,959.33	172.83	78.75	1,386.17	683.92	2,180.08
1976	9,064.00	113.17	78.75	1,394.83	730.50	2,242.75
1977	7,383.33	113.08	78.92	1,298.75	709.75	2,205.75
1978	7,865.08	116.33	79.00	1,343.17	712.83	2,171.67
1979	9,782.75	116.25	78.75	1,344.58	712.92	2,171.08
1980	13,420.00	116.17	46.83	1,248.25	695.50	2,129.08
1981	14,906.75	105.25	46.58	1,248.25	694.42	2,126.58
1982	13,780.75	105.42	46.83	1,319.67	630.25	2,049.83

Source: Monthly averages for each year were calculated by the Energy Information Administration, Electric Power Division, based on monthly data from PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C44. Capacity Utilization Ratios for Fossil-Fuel Steam in the Pacific Northwest Region, 1972-1982

Year	Coal	Oil	Gas
1972	0.4170	0.0690	0.2694
1973	0.4606	0.0631	0.1659
1974	0.3652	0.0352	0.2163
1975	0.3772	0.0522	0.1804
1976	0.3677	0.0401	0.1394
1977	0.6536	0.0583	0.1281
1978	0.5939	0.0569	0.1114
1979	0.5325	0.0790	0.1354
1980	0.4411	0.0457	0.1319
1981	0.4153	0.0287	0.0569
1982	0.4555	0.0270	0.0277

Note: Capacity utilization ratios for each fuel were calculated by Energy Information Administration, Electric Power Division, by taking the ratio of actual generation for the year to the potential generation based on the highest reported monthly available capacity for the year.

Sources: •Generation data: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms. •Capacity data: PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C45. Net Generation of Electricity in the Pacific Southwest Region, 1972-1982 (Gigawatthours)

Year	Total[a]	Coal	Share (%)	Oil	Share (%)	Gas	Share (%)	Nuclear	Share (%)	Hydro-electric	Share (%)
1972	171,445	20,575	12	27,536	16	78,566	46	3,175	2	40,109	23
1973	187,102	22,000	12	52,119	28	60,686	32	2,631	1	47,675	25
1974	174,333	26,916	15	45,427	26	40,329	23	3,698	2	55,490	32
1975	179,009	30,511	17	53,942	30	36,124	20	6,071	3	49,095	27
1976	179,675	35,920	20	64,007	36	38,920	22	4,807	3	32,386	18
1977	204,877	41,104	20	83,219	41	46,338	23	8,115	4	22,490	11
1978	199,834	35,564	18	65,750	33	41,955	21	7,659	4	45,912	23
1979	221,693	43,037	19	65,912	30	57,139	26	8,762	4	42,944	19
1980	215,426	48,789	23	41,841	19	61,716	29	4,921	2	53,066	25
1981	208,745	55,557	27	28,253	14	77,620	37	3,237	2	38,369	18
1982	195,191	60,719	31	9,973	5	57,152	29	3,765	2	58,725	30

[a]Total includes generation from refuse and wood.

Note: Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms.

Appendix C

Table C46. Fossil-Fuel Costs for Electric Generation in the Pacific Southwest Region, 1972-1982 (Dollars per Million Btu)

Year	Weighted Average[a]	Coal[b]	Oil[c]	Gas[d]
1972	0.44	0.20	0.79	0.38
1973	0.60	0.21	0.95	0.42
1974	1.06	0.22	1.99	0.59
1975	1.46	0.26	2.45	1.01
1976	1.52	0.31	2.34	1.46
1977	1.78	0.43	2.38	1.97
1978	1.82	0.52	2.56	2.00
1979	2.21	0.74	3.16	2.38
1980	2.97	0.84	5.00	3.32
1981	3.29	0.94	6.63	3.79
1982	3.16	1.04	6.74	4.86

[a]Quantity weighted average cost using Btu of coal, oil, and natural gas delivered to power plants.
[b]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[c]Includes fuel oil Nos. 2, 4, 5, and 6 as well as crude oil, topped crude, kerosene, and jet fuel.
[d]Includes natural gas, coke oven gas, blast furnace gas, and refinery gas.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Appendix C

Table C47. Monthly Average Available Fossil Fuel Steam Capacity by Fuel in the Pacific Southwest Region, 1972-1982 (Megawatts)

Year	Capacity: Single Fuel: Coal	Capacity: Single Fuel: Oil	Capacity: Single Fuel: Gas	Capacity: Multifuel: Coal	Capacity: Multifuel: Oil	Capacity: Multifuel: Gas
1972	8,268.50	5.67	41.00	1,860.17	21,798.67	24,074.00
1973	8,440.50	5.42	39.50	2,521.83	21,839.25	24,236.17
1974	10,154.58	5.42	0	2,445.42	21,920.50	24,378.33
1975	11,677.58	0	0	2,405.92	22,267.58	24,656.83
1976	14,493.00	0	300.08	1,868.17	21,405.25	24,225.83
1977	14,989.67	0	219.75	2,107.42	21,653.08	24,130.33
1978	15,132.83	62.17	230.92	2,118.67	21,614.08	24,007.58
1979	16,544.83	238.42	217.25	2,139.08	20,706.08	24,211.58
1980	18,046.75	233.17	212.42	2,248.33	21,289.08	23,684.67
1981	17,264.67	251.08	218.92	2,347.25	20,900.83	23,349.58
1982	18,077.67	251.25	220.67	2,347.00	20,272.33	23,587.83

Source: Monthly averages for each year were calculated by the Energy Information Administration, Electric Power Division, based on monthly data from PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

Appendix C

Table C48. Capacity Utilization Ratios for Fossil-Fuel Steam in the Pacific Southwest Region, 1972-1982

Year	Coal	Oil	Gas
1972	0.2202	0.1659	0.3634
1973	0.2117	0.2476	0.2531
1974	0.2255	0.2161	0.1671
1975	0.2202	0.2503	0.1507
1976	0.2183	0.3092	0.1602
1977	0.2590	0.4038	0.1948
1978	0.2174	0.3086	0.1704
1979	0.2403	0.3131	0.2337
1980	0.2521	0.1978	0.2551
1981	0.2735	0.1328	0.3080
1982	0.3184	0.0492	0.2399

Note: Capacity utilization ratios for each fuel were calculated by Energy Information Administration, Electric Power Division, by taking the ratio of actual generation for the year to the potential generation based on the highest reported monthly available capacity for the year.

Sources: •Generation data: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and predecessor forms. •Capacity data: PEDCo Environmental Inc., "Data Tabulations of Monthly Fossil Fuel Steam Electric Generating Capacity 1972-1982," Final Draft.

☆U.S. GOVERNMENT PRINTING OFFICE:1985-461-195:20024

1982

Form Approved
OMB No. 1902-0021
(Expires 12/31/84)

FERC FORM NO. 1: ANNUAL REPORT OF ELECTRIC UTILITIES, LICENSEES AND OTHERS (Class A and Class B)

138-92-0029
11/24-51-7-6

This report is mandatory under the Federal Power Act, Sections 3,4(a), 304 and 309, and 18 CFR 141.1. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	Dec. 31, 19 82

Form Approved
OMB No. 1902-0021
(Expires 12/31/84)

FERC FORM NO. 1: ANNUAL REPORT OF ELECTRIC UTILITIES, LICENSEES AND OTHERS (Class A and Class B)

This report is mandatory under the Federal Power Act, Sections 3,4(a), 304 and 309, and 18 CFR 141.1. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	Dec. 31, 19 82

Coopers & Lybrand

certified public accountants

To the Stockholders and Board of Directors of
Virginia Electric and Power Company:

In connection with our regular examination of the financial statements of Virginia Electric and Power Company for the year ended December 31, 1982, on which we have reported separately under date of February 4, 1983 in the Company's 1982 Annual Report to Stockholders, which report was qualified with reference to the effects on the 1982 financial statements of such adjustments, if any, as might have been required had the recoverability of the amount deferred relating to the cancellation of North Anna Unit 3 and any subsequent cancellation costs been known, we have also reviewed schedules as set forth in the list attached, included in Form 1 for 1982, filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, the schedules set forth on the attached list conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

Coopers & Lybrand

New York, New York
February 4, 1983.

INDEX of SCHEDULES

INSTRUCTIONS FOR FILING THE FERC FORM NO. 1

GENERAL INFORMATION

I. Purpose

This form is a regulatory support requirement (18 CFR 141.1). It is designed to collect financial and operational information from public utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. This report is also secondarily considered to be a non-confidential public use form supporting a statistical publication (Statistics of Privately Owned Electric Utilities in the United States) published by the Energy Information Administration.

II. Who Must Submit

Each Class A and Class B public utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 CFR 101) must submit this form.

Note: Class A means having annual electric operating revenues of $2,500,000 or more.
Class B means having annual electric operating revenues of more than $1,000,000 but less than $2,500,000.

III. What and Where to Submit

(a) Submit an original and six (6) copies of this form to:

U S Department of Energy
Energy Information Administration, EI-414
Mail Station: 8E 079
Forrestal Building
Washington, D.C. 20585

Retain one copy of this report for your files.

(b) Submit immediately upon publication, four (4) copies of the latest annual report to stockholders and any *annual* financial or statistical report regularly prepared and distributed to bondholders, security analyst, or industry association. (Do not include monthly and quarterly reports. If reports to stockholders are not prepared, enter "NA" in column (d) on Page 4, the List of Schedules.) Mail these reports to:

Chief Accountant
Federal Energy Regulatory Commission
825 N. Capitol St., N.E.
Room 601-RB
Washington, D.C. 20426

(c) For the CPA certification, submit with the original submission, or within 30 days after the filing date for this form, a letter or report:

(i) Attesting to the conformity, in all material aspects, of the below listed (schedules and) pages with the Commission's applicable Uniform Systems of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

(ii) Signed by independent certified public accountants or an independent licensed public accountant, certified or licensed by a regulatory authority of a State or other political subdivision of the U.S. (See 18 CFR 41.10-41.12 for specific qualifications.)

Schedules	Reference Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Changes in Financial Position	120-121
Notes to Financial Statements	122-123

When accompanying this form, insert the letter or report immediately following the cover sheet.

GENERAL INFORMATION (Continued)

III. What and Where to Submit (Continued)

(c) (Continued)

Use the following form for the letter or report unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

In connection with our regular examination of the financial statement of for the year ended on which we have reported separately under date of we have also reviewed schedules of form 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

State in the letter or report which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(d) Federal, State and Local Governments and other authorized users may obtain additional blank copies to meet their requirements free of charge from:

U.S. Department of Energy
National Energy Information Center
Energy Information Administration
Washington, D.C. 20585
(202) 252-8800

IV. When to Submit:

Submit this report form on or before April 30th of the year following the year covered by this report

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18CFR 101) (U.S. of A.). Interpret all accounting words and phrases in accordance with the U.S. of A.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting year, and use for statement of income accounts the current years amounts.

III. Complete each question fully and accurately, even if it has been answered in a previous annual report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, either

a) Enter the words "Not Applicable" on the particular page(s), or

(b) Omit the page(s) and enter "NA", "None", or "Not Applicable" in column (d) on the List of Schedules, pages 2, 3, and 4.

V. Complete this report by means which result in a permanent record. Complete the original copy in permanent black ink or typewriter print, if practical. The copies, however, may be carbon copies or other similar means of reproduction provided the impressions are clear and readable.

GENERAL INSTRUCTIONS (Continued)

VI. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" at the top of each page is applicable only to resubmissions (see VIII. below).

VII. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses ( ).

VIII. When making revisions, resubmit only those pages that have been changed from the original submission. Submit the same number of copies as required for filing the form. Include with the resubmission the Identification and Attestation page, page 1. Mail dated resubmissions to:

Chief Accountant
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Room 601-RB
Washington, D.C. 20426

IX. Provide a supplemental statement further explaining accounts or pages as necessary. Attach the supplemental statement (8½ by 11 inch size) to the page being supplemented. Provide the appropriate identification information, including the title(s) of the page and the page number supplemented.

X. Do not make references to reports of previous years or to other reports in lieu of required entries, except as specifically authorized.

XI. Wherever (schedule) pages refer to figures from a previous year, the figures reported must be based upon those shown by the annual report of the previous year, or an appropriate explanation given as to why the different figures were used.

XII. Respondents may submit computer printed schedules (reduced to 8½ by 11) instead of the preprinted schedules if they are in substantially the same format.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) — The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent — The person, corporation, licensee, agency, authority, or other legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

(Federal Power Act, 16 U.S.C. 791a-825r)

"Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to wit:

...(3) 'corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities' as hereinafter defined;

(4) 'person' means an individual or a corporation;

(5) 'licensee' means any person, State, or municipality licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality' means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the laws thereof to carry on the business of developing, transmitting, utilizing, or distributing power;...."

(11) 'project' means a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, a forebay reservoirs directly connected therewith, the primary line or lines transmitting power therefrom to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit as any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, lands, or interest in lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

EXCERPTS FROM THE LAW (Continued)

"Sec. 4. The Commission is hereby authorized and empowered—

(a) To make investigations and to collect and record data concerning the utilization of the water resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites, ...to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every licensee and every public utility shall file with the Commission such annual and other periodic or special reports as the Commission may by rules and regulations or order prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies."

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the form or forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be filed...."

GENERAL PENALTIES

"Sec. 315. (a) Any licensee or public utility which willfully fails, within the time prescribed by the Commission, to comply with any order of the Commission, to file any report required under this Act or any rule or regulation of the Commission thereunder, to submit any information or document required by the Commission in the course of an investigation conducted under this Act,...shall forfeit to the United States an amount not exceeding $1,000 to be fixed by the Commission after notice and opportunity for hearing...."

FERC FORM NO 1:
ANNUAL REPORT OF ELECTRIC UTILITIES, LICENSEES AND OTHERS (Class A and Class B)

IDENTIFICATION

01 Exact Legal Name of Respondent Virginia Electric and Power Company	02 Year of Report Dec. 31, 19 82
03 Previous Name and Date of Change *(If name changed during year)*	
04 Address of Principal Business Office at End of Year *(Street, City, State, Zip Code)* One James River Plaza, Richmond, Virginia 23261	
05 Name of Contact Person R. C. Houghton, Jr.	06 Title of Contact Person Director - Regulatory Services
07 Address of Contact Person *(Street, City, State, Zip Code)* One James River Plaza, Richmond, Virginia 23261	

08 Telephone of Contact Person, *Including Area Code* (804) 771-3887	09 This Report Is (1) ☒ An Original (2) ☐ A Resubmission	10 Date of Report *(Mo, Da, Yr)*

ATTESTATION

The undersigned officer certifies that he/she has examined the accompanying report; that to the best of his/her knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the above named respondent in respect to each and every matter set forth therein during the period from and including January 1 to and including December 31 of the year of the report.

01 Name B. D. Johnson	03 Signature B D Johnson	04 Date Signed *(Mo, Da, Yr)* 04-28-83
02 Title Vice President and Controller		

Title 18, U.S.C. 1001, makes it a crime for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec 31 19 82

LIST OF SCHEDULES (Electric Utility)

Enter in column (d) the terms "none," "not applicable," or "NA" as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the responses are "none," "not applicable," or "NA."

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

LIST OF SCHEDULES (Electric Utility) (Continued)

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

LIST OF SCHEDULES (Electric Utility) (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1982

GENERAL INFORMATION

1. *Provide name and title of officer having* custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

B. D. Johnson, Vice President and Controller
One James River Plaza
Richmond, Virginia 23261

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Virginia - June 29, 1909

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes of utility and other services furnished by respondent during the year in each State in which the respondent operated.

Virginia - Electric and Gas Utility Service
North Carolina - Electric Utility Service
West Virginia - Electric Utility Service

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) ☐ YES ...Enter the date when such independent accountant was initially engaged:__________.
(2) ☒ NO

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or combination of such organizations jointly held control over the respondent at end of year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

2. If the above required information is available from the SEC 10-K Report Form filing, a specific reference to the report form (i.e. year and company title) may be listed provided the fiscal years for both the 10-K report and this report are compatible.

None

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, *naming any intermediaries involved.*
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.
4. If the above required information is available from the SEC 10-K Report Form filing, a specific reference to the report form (i.e. year and company title) may be listed in column (a) provided the fiscal years for both the 10-K report and this report are compatible.

DEFINITIONS

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
Carolina-Virginia Nuclear Power Associates, Inc.	Non-Profit Research and Development Company	(a)	(a)
Laurel Run Mining Company A wholly owned subsidiary of respondent	Formed to mine the coal reserves of respondent	100%	Direct Control
Virginia Nuclear, Inc. A wholly owned subsidiary of respondent	Formed to acquire leases of mining claims and to determine the feasibility of mining uranium ore under the claims; however, no such activities are presently conducted.	100%	Direct Control

(a) The respondent exercises joint control with three other electric utilities; Duke Power Company, Carolina Power & Light Company, and South Carolina Electric & Gas Company.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policymaking functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and date the change in incumbency was made.
3. Utilities which are required to file the same data with the Securities and Exchange Commission, may substitute a copy of item 4 of Regulation S-K (identified as this page). The substituted page(s) should be the same size as this page.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)

Pursuant to Instruction 3, the following information, prescribed in Item 4 of SEC Regulation S-K, is excerpted from the Company's "Proxy Statement" as filed with the Securities and Exchange Commission.

Remuneration of Directors and officers during 1982 was:

	Salaries, fees, commissions and bonuses	Aggregate of contingent forms of remuneration (a)
T. Justin Moore, Jr.—Chairman of the Board (b)	[illegible]	[illegible]
William W. Berry—President and Chief Executive Officer (b)	[illegible]	[illegible]
Jack H. Ferguson—Executive Vice President and Chief Operating Officer (b)	[illegible]	4,[illegible]46
William L. Proffitt—Senior Vice President	[illegible]	3,218
Samuel C. Brown, Jr.—Senior Vice President	[illegible]	3,20[illegible]
Directors and officers as a group—47 persons (including those named above)	[illegible]	[illegible]

(a) These amounts represent contributions to the Employee Savings Plan.
(b) During 1982, Mr. Moore was Chief Executive Officer and Mr. Berry was Chief Operating Officer.

A Management Incentive Compensation Program has been in effect since [illegible] and the 1983 Program will be presented to the Board at its March 1983 meeting. The Program provides for incentive compensation based on (1) individual achievement of managerial and executive department goals, (2) improvements in earnings per share of Common Stock and (3) [illegible] customers. Amounts earned for the year 1981 are included in the [illegible] above. Amounts earned for the year 1982 under the Program will not be fixed and paid until late March 1983.

A contributory insured Retirement Annuity Plan (the "Retirement Plan") has been in effect since 1945 for officers and employees. The Retirement Plan is integrated with Social Security benefits but amounts shown in the table below do not include such benefits and are not subject to any reductions on account of such benefits. Credited years of service under the Retirement Plan for the individuals named above are as follows: T. Justin Moore, Jr., 26; William W. Berry, [illegible]; Jack H. Ferguson, [illegible]; William L. Proffitt, 27 and Samuel C. Brown, Jr., 27. Effective January 1, 1981 the insurance coverage on elected officers was reduced 50% and at the same time a non-contributory Supplemental Retirement Plan (the "Supplemental Plan") became effective for such officers. Vepco is the beneficiary of insurance policies (unaffiliated with the Retirement Plan) on certain officers and estimates that eventual proceeds will approximate the cost of the insurance and benefits payable under the Supplemental Plan. Under the Retirement Plan and Supplemental Plan, benefits to such officers for the first [illegible] years following retirement would be as follows:

Estimated Annual Benefits Payable Upon Retirement (1)

Remuneration	Credited Years of Service: 15	20	25	30
$ 75,000	$ 35,000	$ 41,[illegible]	$ 46,[illegible]	$ [illegible]
100,000	48,300	56,[illegible]	63,[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	99,2[illegible]	1[illegible]	[illegible]	[illegible]
[illegible]	124,6[illegible]	145,[illegible]	[illegible]	[illegible]
300,000	150,[illegible]	1[illegible]	[illegible]	[illegible]
350,000	175,500	204,800	234,2[illegible]	[illegible]
400,000	200,900	234,600	268,200	301,900

(1) Based on normal retirement at age 65.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a) abbreviated titles of the directors who are officers of the respondent.

2. Designate members of the Executive Committee by an asterisk and the Chairman of the Executive Committee by a double asterisk.

Name (and Title) of Director (a)	Principal Business Address (b)
John B. Bernhardt Director	Virginia National Bank P. O. Box 600 Norfolk, Virginia 23501
William W. Berry President (Chief Executive Officer) and Director	Virginia Electric and Power Comoany P. O. Box 26666 Richmond, Virginia 23261
James P. Betts Director	Continental Financial Services Company 6600 W. Broad Street Richmond, Virginia 23230
Milton L. Drewer, Jr. Director	First American Bank of Virginia 1970 Chain Bridge Road McLean, Virginia 22101
Mrs. Mary C. Fray Director	328 Asher Street Culpeper, Virginia 22701
Bruce C. Gottwald Director	Ethyl Corporation P. O. Box 2189 Richmond, Virginia 23217
Dr. Allix B. James Director	Virginia Union University 1500 North Lombardy Street Richmond, Virginia 23220
T. Justin Moore, Jr. Chairman of Board of Directors	Virginia Electric and Power Comoany P. O. Box 26666 Richmond, Virginia 23261
William S. Peebles, III Director	W. S. Peebles and Company, Inc. P. O. Box 225 Lawrenceville, Virginia 23868
Shirley S. Pierce Director	The Ahoskie Fertilizer Company, Inc. Powellsville Highway Ahoskie, North Carolina 27910
Kenneth A. Randall Director	13 Valley Road New Canaan, Connecticut 06840
William T. Roos Director	P. O. Box 793 Yorktown, Virginia 23692
Roy R. Smith Director	Smith's Transfer Corporation P. O. Box 1000 Staunton, Virginia 24401
William F. Vosbeck, Jr. Director	VVKR Incorporated 901 North Pitt Street Alexandria, Virginia 22314

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SECURITY HOLDERS AND VOTING POWERS

1. Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of list of stockholders of the respondent, prior to the end of the year, had the highest voting powers in the respondent, and state the number of votes which each would have had the right to cast on that date if a meeting were then in order. If any such holder held in trust, give in a footnote the known particulars of the trust (whether voting trust, etc.), duration of trust, and principal holders of beneficiary interests in the trust. If the stock book was not closed or a list of stockholders was not compiled within one year prior to the end of the year, or if since the previous compilation of a list of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.

2. If any security other than stock carries voting rights, explain in a supplemental statement the circumstances whereby such security became vested with voting rights and give other important particulars (details) concerning the voting rights of such security. State whether voting rights are actual or contingent, if contingent, describe the contingency.

3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method, explain briefly in a footnote.

4. Furnish particulars (details) concerning any options, warrants, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or rights. Specify the amount of such securities or assets so entitled to be purchased by any officer, director, associated company, or any of the ten largest security holders. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants, or rights were issued on a prorata basis.

1. Give date of the latest closing of the stock book prior to end of year, and state the purpose of such closing:	2. State the total number of votes cast at the latest general meeting prior to the end of year for election of directors of the respondent and number of such votes cast by proxy	3. Give the date and place of such meeting
December 31, 1982 (The Company does not "close" its books)	Total 85,056,498 By proxy 85,032,150	April 21, 1982 One James River Plaza Richmond, Virginia

Line No	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES — Number of votes as of (date): December 31, 1982 - 119,517,688 — Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
4	TOTAL votes of all voting securities as of December 31, 1982	119,517,688	119,517,688		
5	TOTAL number of security holders as of December 31, 1982	207,973	207,973		
6	TOTAL votes of security holders listed below as of December 31, 1982	32,084,047	32,084,047		
7					
8	Merrill Lynch, Pierce, Fenner & Smith, Inc., P. O. Box 12175, Church Street Station, New York, New York 10019	7,938,670	7,938,670		
9	Penwill, c/o United Virginia Bank, Trust Dept., P. O. Box 26246, Richmond, Virginia 23260	5,737,136	5,737,136		
10	Chase Manhattan Bank, N.A., One Chase Manhattan Plaza, New York, New York 10081	4,285,956	4,285,956		
11	Bankers Trust Company, 130 Liberty Plaza--18th Floor, New York, New York 10004	3,903,185	3,903,185		
12	Bova & Company, c/o Bank of Virginia Trust Co., 7 North Eighth Street, P. O. Box 26311, Richmond, Virginia 23260	3,031,947	3,031,947		
13	Morgan Guaranty Trust Company of New York, 40 Wall Street, New York, New York 10005	1,645,560	1,645,560		
14	Prudential-Bache Securities Inc., 100 Gold Street, New York, New York 10038	1,498,341	1,498,341		
14	SSB-Custodian, c/o IDCA, 7 Delaware Drive, Lake Success, New York 11042	1,489,800	1,489,800		
15	E. F. Hutton & Co., Inc., 26 Broadway, New York, New York 10019	1,374,457	1,374,457		
16	Northern Trust Company, 50 South LaSalle Street, Chicago, Illinois 60675	1,178,995	1,178,995		
17					
18					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SECURITY HOLDERS AND VOTING POWERS (Continued)

Line No.	Name (Title) and Address of Security Holder (a)	Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

IMPORTANT CHANGES DURING THE YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefor and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.

2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.

3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.

4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other conditions. State name of Commission authorizing lease and give reference to such authorization.

5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements etc.

6. Obligation incurred or assumed by respondent as guarantor for the performance by another of any agreement or obligation, including ordinary commercial paper maturing on demand or not later than one year after date of issue: State on behalf of whom the obligation was assumed and amount of the obligation. Give reference to Commission authorization if any was required.

7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.

8. State the estimated annual effect and nature of any important wage scale changes during the year.

9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.

10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on page 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.

11. (Reserved.)

12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by instructions 1 to 11 above, such notes may be attached to this page.

1. Changes in franchises during 1982:

Location	Acquired	Expiration Of Former Franchise	Term (Years)	Consideration	Bond
Orange, VA	4-12-82	4-21-82	20(a)	$ 500	$ 1,000
Iron Gate, VA	6-24-82	5-19-82	40	$ 400	$ 1,000
Fairfax, VA	7-20-82	6-04-82	30	$2,500	$ 1,000
Warrenton, VA	7-06-82	7-08-82	15(b)	$ 500	$10,000
Hillsboro, VA	6-09-82	9-05-82	40	$ 200	$ 1,000
Pocahontas County, W.VA	5-04-82	4-05-82	50	NONE	$ 1,000

(a) With an option for 20 more years.
(b) With an option for 15 more years.

2. None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

IMPORTANT CHANGES DURING THE YEAR (Continued)

3.(a) Negotiations for the purchase by Old Dominion Electric Cooperative of a 12.5% ownership interest in the Company's North Anna Units 1 and 2 and associated facilities (including nuclear fuel) resulted in the signing of definitive agreements, dated as of December 28, 1982.

The agreements must be approved by the Virginia Commission, the West Virginia Public Service Commission, the Nuclear Regulatory Commission, and the Rural Electrification Administration. The Federal Energy Regulatory Commission also has jurisdiction over certain aspects of the transaction. The Company has filed necessary applications with regulatory authorities, but it is not yet possible to predict whether or when the required regulatory authorizations will be granted.

(b) On April 27, 1982, the Company received $194.3 million from Allegheny Power System, Inc. (APS) for the sale of approximately 20% of the ownership interest in the Company's Bath County Pumped Storage Hydroelectric Project (the Project). This initial payment represented approximately 20% of the construction costs already incurred by the Company on the Project. Subsequent payments brought the total amount received from APS in 1982 to $218 million. APS also will pay 20% of future construction costs.

Under the terms of the sale, APS also committed to purchase either an additional 20% ownership interest in the Project or an additional 20% of the Project's generating capacity under a long-term contract. If APS chooses to purchase an additional 20% equity interest, the result will be a further reduction of approximately $300 million in the Company's share of the Project's costs. Subject to further regulatory approvals, APS has an option until the end of 1984 to increase its participation in the Project to 50%.

Necessary regulatory approvals for the sale were obtained in Virginia, Ohio, West Virginia, FERC, Pennsylvania, Maryland and at the SEC.

Journal Entries called for by the Uniform System of Accounts were submitted to the Federal Energy Regulatory Commission on June 30, 1982.

4. None

5. In December, 1981, eleven of the Company's North Carolina municipal customers terminated contracts for electric service by the Company to purchase their own generating capacity from another utility. Accordingly, the Company agreed to phase out its wholesale power contracts with these customers over a two-year period beginning December 30, 1981, in return for a payment to the Company on that date of approximately $15.5 million. These customers accounted for about 3.0% of the Company's electric revenues during 1981. On December 10, 1982, the Company sold Substation Facilities at Greenville, North Carolina to Carolina Power & Light Company and the Greenville Utilities Commission for the City of Greenville North Carolina, pursuant to Section 203(a) of the Federal Power Act and to Part 33 of the regulations under the Federal Power Act. This sale was approved by the Federal Energy Regulatory Commission under Docket No. EC82-10-000.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

IMPORTANT CHANGES DURING THE YEAR (Continued)

6. None

7. The Articles of Incorporation were amended during 1982 as follows:

Effective January 25, 1982, by Articles of Reduction relating to the shares of $8.60 Dividend Preferred Stock which were redeemed and cancelled pursuant to the mandatory sinking fund provisions of that series.

Effective May 7, 1982, by Articles of Amendment, increased authorized shares of Common Stock from 120,000,000 to 150,000,000.

Effective October 6, 1982, by Articles of Reduction relating to the shares of $9.125 Dividend Preferred Stock which were redeemed and cancelled pursuant to the mandatory sinking fund provisions of that series.

8.(a) As a result of renegotiation of wage rates under the collective labor contract with non-supervisory employees in the electric and gas production and maintenance departments, wages were increased on April 1, 1982 by approximately 9.5%.

(b) As a result of an NLRB election held on July 28 and 29, 1982, the Utility Employees Association ceased to represent the non-supervisory office and clerical, and scientific, professional, and technical employees. However, a general wage adjustment of approximately 9.5% was granted on October 1, 1982 to these formerly-represented employees.

(c) It is estimated that the general wage adjustments granted in 1982 will increase labor costs by $13,290,394 annually, of which approximately $9,127,417 will be charged to expenses and approximately $4,162,977 will be charged to capital and other accounts.

9.(a) During 1982, the Company has received rate relief as shown below:

Annualized Rate Relief - Millions of Dollars

Virginia	$ 80.4
North Carolina	11.8
FERC	18.1
Federal Government Customers...........	6.8
West Virginia	1.2
Commonwealth of Virginia	1.8
Virginia Gas	3.7
National Aeronautics and Space Administration	.5
County and Municipal	10.0
Total	$134.3

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

IMPORTANT CHANGES DURING THE YEAR (Continued)

(b) On March 31, 1982, the Company requested approval from the Virginia Commission for an increase in revenues of $96 million annually. An interim increase of $80.5 million, subject to refund, was made effective May 1, 1982. The Commission approved $80.4 million on a permanent basis effective August 30, 1982. The rate increase approved reflected an allowed return on common equity of 15%.

(c) In January 1982, the Company filed with the North Carolina Commission an application for a rate increase of $20.5 million (subsequently modified by the Company to $14.7 million). On August 26, 1982, the Commission approved $11.8 million. In doing so, the Commission eliminated a penalty imposed in 1981 and raised the authorized return on common equity from 10% to 15.5%. The rate increase went into effect in two steps, $3.6 million on September 6, 1982 and an additional $8.2 million on October 28, 1982.

(d) In June 1982, the North Carolina General Assembly amended the statute that previously required inclusion of Construction Work in Progress (CWIP) in rate base so as to authorize the North Carolina Commission to determine the amount of CWIP to be included in rate base.

(e) The West Virginia Commission approved, effective July 1, 1982, $1.2 million of the $2.9 million rate request filed in August of 1981. On August 3, 1982, the Company filed an application for an annual increase of $2.2 million. The Commission suspended the increase until June 14, 1983 and has set the matter for hearing on March 28, 1983.

(f) On June 28, 1982, FERC issued a final order approving an increase in revenues of $32.4 million ($9.3 million for municipal customers and $23.1 million for cooperative customers). The increase had gone into effect, subject to refund, in September 1981 at an annual rate of $38 million, and appropriate refunds have been made.

(g) The FERC order also terminated the formal private investigation into the Company's operations that had commenced in March 1980. The order imposed several conditions on the Company, including semi-annual reporting requirements for the next three years on fossil unit operation and maintenance, coal procurement, and construction contracting and administration. The order also required the development of a method by which the Company's allowed return on equity would be adjusted to reflect generating unit performance.

(h) In March 1982, a request was filed with FERC for increases of $3.7 million and $14.6 million for wholesale municipal and cooperative customers, respectively. The proposed increases, subsequently modified in June 1982 to an aggregate of $22.1 million to reflect comprehensive tax normalization, were suspended until September 2, 1982, when rates went into effect subject to refund. A settlement has been negotiated and was filed with FERC on November 17, 1982, that will provide increases of $3.9 million for municipal customers and $14.2 million for cooperative customers.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

IMPORTANT CHANGES DURING THE YEAR (Continued)

(i) In July 1982, a request was filed for an annual increase of $4.9 million in gas rates with the Virginia Commission. On December 20, 1982, the Commission granted an increase of $3.7 million, including a return on equity of 15%, effective immediately.

(j) The Public Staff of the North Carolina Commission appealed the Commission's approval of the Company's fuel charge for April-July 1981 (involving $3.2 million). The case was argued before the North Carolina Court of Appeals on February 17, 1983, but a decision has not yet been rendered.

(k) In April 1980, the West Virginia Commission established a semi-annual fuel cost review procedure. Effective January 1, 1983, the Commission approved a fuel factor increase of $1.7 million annually pursuant to such procedure.

(l) Louisa County, where North Anna is located, has adopted an ordinance prohibiting the storage of spent nuclear fuel in that county unless it results from the operation of the North Anna units. This ordinance, if valid, would make implementation of the Company's spent fuel storage program impossible. On July 20, 1982, the Company filed suit against Louisa County in the United States District Court for the Eastern District of Virginia, seeking a declaration that the ordinance is invalid. On March 4, 1983, the Court found that the ordinance violates the United States Constitution and is unenforceable. The County has appealed the decision.

Certain regulatory approvals are required in connection with the Company's plans for spent fuel shipment and storage. On July 28, 1982, the Company received NRC approval for one primary and four alternate routes to be used for shipping spent fuel from Surry to North Anna. All of the routes necessarily go through Louisa County, and two of the alternate routes go through adjoining Spotsylvania County. Both Counties have asked NRC to rescind the approvals and have petitioned for review of the NRC approvals in the U.S. Court of Appeals for the District of Columbia Circuit. The Company must also obtain the approval of the Virginia Department of Health for its proposed shipments, and, in connection with that approval, several public hearings will be held at different places in the State. In addition, Louisa County is reported to be considering a proposed ordinance that would effectively prohibit shipments of spent nuclear fuel through that county. If such an ordinance were adopted and upheld by the courts, the Company could not carry out its spent fuel shipment plans.

In addition to approval of the proposed shipping routes, the Company requires and has applied for two NRC license amendments. Louisa County and certain members of the public have intervened in both of those proceedings, and public hearings must be held before NRC acts on the applications. Motions to delay these proceedings have been denied.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1982

IMPORTANT CHANGES DURING THE YEAR (Continued)

In an appeal by intervenors contesting NRC's approval of an earlier spent fuel storage capacity enlargement at North Anna, the United States Court of Appeals for the District of Columbia declined to vacate or condition the Company's license. But it indicated that unless NRC reaches a favorable decision by June 30, 1983, in its current generic proceeding to determine whether spent fuel can be safely disposed of in the future, the Court may forbid the Company to store in the North Anna spent fuel pool any more spent fuel than it could have stored had its original capacity not been expanded. As a result, if NRC fails to reach a favorable decision by June 30, 1983, the Company could be forced to shut down the North Anna Units in late 1984 and would not be able to store Surry spent fuel at North Anna.

The NRC has amended its regulations in a way that will require the Company to submit to the NRC, by May 20, 1983, a schedule for either (a) establishing that certain equipment important to safety in nuclear plants is capable of performing its intended function in the environment created by a nuclear accident or (b) replacing such equipment. The Company is unable to predict what effect, if any, compliance with the new regulations will have on the Company's operations. It could result in increases in the cost of reactor operations and in expensive outages. The new regulations and the interim regulations they replace have the effect of superseding the NRC's previous June 1982 deadline for environmental qualifications compliance. The Union of Concerned Scientists has challenged the suspension of the June 1982 deadline in the U.S. Court of appeals for the District of Columbia. In light of the new regulations, NRC has moved the court to dismiss the appeal as moot.

(m) The National Wildlife Federation has petitioned EPA to require operating discharge permits for hydroelectric installations. EPA refused and the Federation brought suit in the U.S. District Court for the District of Columbia. The Company and other utilities intervened opposing the Federation request. On January 29, 1982, the Court entered a decision adverse to EPA and the Company. On November 5, 1982, the decision was reversed by the U.S. Court of Appeals for the District of Columbia Circuit. Unless the Federation obtains review and reversal by the U.S. Supreme Court, no discharge permits will be required for hydroelectric installations.

(n) In an examination report dated February 4, 1980, the District Director of Internal Revenue at Richmond, Virginia, (District Director) asserted a $37,274,014 deficiency in the Company's federal income tax payments for the years 1976-77. The Company will owe interest on any net deficiency found due for those years.

The Company filed a protest with the Appellate Division of the Internal Revenue Service (Appellate Division) contesting most of the liabilities asserted in the examination report. After conferences with the Appellate Division on the Issues raised by the protest, the Company and the

Name of Respondent	This Report Is	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec 31, 1982

IMPORTANT CHANGES DURING THE YEAR (Continued)

Appellate Division's conferee have agreed to a settlement of the contested liabilities that the Company believes would reduce the asserted deficiency to about $211,487, net of investment tax credit. Final settlement is subject to the approval of the Appellate Division.

(o) In an examination report dated March 3, 1982, the District Director asserted a $29,384,759 deficiency in the Company's federal income tax payments for the years 1978-79. Included in such deficiency is an amount based on the application of a ruling from the Internal Revenue Service concerning the federal income tax consequences of the company's 1979 settlement of litigation against Westinghouse Electric Corporation over Westinghouse's repudiation of certain uranium fuel supply contracts. The Company will owe interest on any net deficiency found due for those years.

The Company has filed a protest with the Appellate Division contesting most of the liabilities asserted in the examination report. We presently are unable, however, to predict the outcome of the proceeding with the Appellate Division or to determine the amount of any final deficiency for the 1978-79 years.

(p) The Company, together with six other electric utilities, on May 29, 1978, filed suit in the Circuit Court of Kanawha County, West Virginia, challenging the legality of a 4% tax on electricity generated in West Virginia and sold out of state. The tax which the Company has paid under protest amounted to an aggregate of $27.7 million for 1978 through 1982. The Court has not yet rendered a decision.

(q) As to various suits against the Company, alleging personal injury, wrongful death or property damage, the Company maintains insurance for these suits that covers its liability in excess of $100,000 in any such suit up to a total of $25,000,000 for any such suit. The Company believes that the estimated settlement net of insurance proceeds for all such suits will not exceed $425,000.

(r) The company is involved in several investigations and proceedings regarding equal employment opportunity requirements, including an Equal Employment Opportunity Commission charge filed against the Company in August 1977. The charge contains broad, general allegations of sex discrimination in all phases of employment. The Commission has conducted an investigation but has not yet made any administrative determination with respect to the allegations. Until such time as the issues are clarified by the Commission, it is not possible to determine the materiality of the charge.

10. None
11. (Reserved)
12. Not Applicable.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric & Power Co.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec 31, 19 82

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	UTILITY PLANT		(DOLLARS)	
2	Utility Plant (101-106, 114)	200	5,514,535,996	5,890,569,520
3	Construction Work in Progress (107)	200	1,616,880,071	1,196,296,767
4	TOTAL Utility Plant *(Enter Total of lines 2 and 3)*		7,131,416,067	7,086,866,287
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200	1,263,866,721	1,421,849,007
6	Net Utility Plant, Less Nuclear Fuel *(Enter Total of line 4 less 5)*	–	5,867,549,346	5,665,017,280
7	Nuclear Fuel (120.1-120.4)	201	356,217,881	397,523,190
8	(Less) Accum. Prov. for Amort. of Nuclear Fuel Assemblies (120.5)	201	210,878,606	271,496,558
9	Net Nuclear Fuel *(Enter Total of line 7 less 8)*	–	145,339,275	126,026,632
10	Net Utility Plant *(Enter Total of lines 6 and 9)*	–	6,012,888,621	5,791,043,912
11	Utility Plant Adjustments (116)			
12	Gas Stored Underground-Noncurrent (117)	–		
13	OTHER PROPERTY AND INVESTMENTS			
14	Nonutility Property (121)	215	13,129,489	12,932,554
15	(Less) Accum. Prov. for Depr. and Amort. (122)	–	7,657,244	6,678,349
16	Investments in Associated Companies (123)	–		
17	Investment in Subsidiary Companies (123.1)	217	21,281,748	21,256,474
18	*(For cost of Account 123.1, see footnote for line 23, page 217)*	–		
19	Other Investments (124)	–		
20	Special Funds (125-128)	–		
21	TOTAL Other Property and Investments *(Enter Total of lines 14 thru 20)*	–	26,753,993	27,510,679
22	CURRENT AND ACCRUED ASSETS			
23	Cash (131)	–	16,552,043	15,085,132
24	Special Deposits (132-134)	–	456,786	290,319
25	Working Funds (135)	–	117,494	355,399
26	Temporary Cash Investments (136)	–		7,000,000
27	Notes Receivable (141)	–		
28	Customer Accounts Receivable (142)	–	186,664,642	208,878,311
29	Other Accounts Receivable (143)	–	19,271,487	5,890,186
30	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)	–	2,001,592	2,342,698
31	Notes Receivable from Associated Companies (145)	–		
32	Accounts Receivable from Assoc. Companies (146)	–	17,107	(16,323)
33	Fuel Stock (151)	218	129,557,166	125,280,523
34	Fuel Stock Expense Undistributed (152)	218		
35	Residuals (Elec) and Extracted Products (Gas) (153)	218		
36	Plant Material and Operating Supplies (154)	218	77,001,197	141,075,759
37	Merchandise (155)	218		
38	Other Material and Supplies (156)	218		
39	Nuclear Materials Held for Sale (157)	201/218		
40	Stores Expenses Undistributed (163)	218	(77,427)	283,456
41	Gas Stored Underground – Current (164.1)	–		
42	Liquefied Natural Gas Stored (164.2)	–		
43	Liquefied Natural Gas Held for Processing (164.3)	–		
44	Prepayments (165)	–	47,675,524	40,391,731
45	Advances for Gas Explor., Devel. and Prod. (166)	–		
46	Other Advances for Gas (167)	–		
47	Interest and Dividends Receivable (171)	–	2	9,360
48	Rents Receivable (172)	–	221,203	1,070,265
49	Accrued Utility Revenues (173)	–	93,551,000	82,538,895
50	Miscellaneous Current and Accrued Assets (174)	–	5,593,300	668,257
51	TOTAL Current and Accrued Assets *(Enter Total of lines 23 thru 50)*		574,599,932	626,458,572

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric & Power Co.	(1) [X] An Original (2) [ ] A Resubmission		Dec 31, 19 82

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS) (Continued)

Line No.	Title of Account (a)	Ref Page No (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
52	DEFERRED DEBITS		(DOLLARS)	
53	Unamortized Debt Expense (181)	–	8,970,848	8,199,871
54	Extraordinary Property Losses (182)	220	193,111,574	628,418,897
55	Prelim. Survey and Investigation Charges (Electric) (183)	–	4,023,549	6,015,256
56	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)	–		
57	Clearing Accounts (184)	–	(194,361)	(401,087)
58	Temporary Facilities (185)	–	33,374	129,552
59	Miscellaneous Deferred Debits (186)	223	236,314,880	269,261,299
60	Def. Losses from Disposition of Utility Plt (187)	–		
61	Research, Devel. and Demonstration Expend (188)	352–353		91,685
62	Unamortized Loss on Reacquired Debt (189)	–		
63	Accumulated Deferred Income Taxes (190)	224	1,329,077	2,627,567
64	Unrecovered Purchased Gas Costs (191)	–		
65	Unrecovered Incremental Gas Costs (192.1)	–		
66	Unrecovered Incremental Surcharges (192.2)	–		
67	TOTAL Deferred Debits *(Enter Total of lines 53 thru 66)*		443,588,941	914,343,040
68	TOTAL Assets and other Debits *(Enter Total of lines 10, 11, 12, 21, 51, and 67)*		7,057,831,487	7,359,356,203

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric & Power Co.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Omit Cents: Balance at Beginning of Year (c)	Omit Cents: Balance at End of Year (d)
1	PROPRIETARY CAPITAL		(DOLLARS)	
2	Common Stock Issued (201)	250	1,454,042,502	1,642,714,066
3	Preferred Stock Issued (204)	250	675,284,400	673,301,000
4	Capital Stock Subscribed (202, 205)	251		
5	Stock Liability for Conversion (203, 206)	251		
6	Premium on Capital Stock (207)	251		
7	Other Paid-In Capital (208-211)	252	24,515,995	23,680,223
8	Installments Received on Capital Stock (212)	251	3,029,994	3,114,490
9	(Less) Discount on Capital Stock (213)	253		
10	(Less) Capital Stock Expense (214)	253		
11	Retained Earnings (215, 215.1, 216)	118-119	470,888,012	519,186,779
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119		
13	(Less) Reacquired Capital Stock (217)	250		
14	TOTAL Proprietary Capital *(Enter Total of lines 2 thru 13)*	–	2,627,760,903	2,861,996,558
15	LONG-TERM DEBT			
16	Bonds (221)	257	2,492,940,000	2,540,224,000
17	(Less) Reacquired Bonds (222)	257		
18	Advances from Associated Companies (223)	257		
19	Other Long-Term Debt (224)	257	770,150,000	664,500,000
20	Unamortized Premium on Long-Term Debt (225)		740,242	667,504
21	(Less) Unamortized Discount on Long-Term Debt-Dr. (226)		10,816,715	11,402,620
22	TOTAL Long-Term Debt *(Enter Total of lines 16 thru 21)*	–	3,253,013,527	3,193,988,884
23	CURRENT AND ACCRUED LIABILITIES			
24	Notes Payable (231)	–	164,938,000	103,333,000
25	Accounts Payable (232)	–	104,148,635	121,846,144
26	Notes Payable to Associated Companies (233)	–		
27	Accounts Payable to Associated Companies (234)	–	204,026	204,026
28	Customer Deposits (235)	–	14,423,725	21,775,169
29	Taxes Accrued (236)	258-259	74,730,470	69,060,140
30	Interest Accrued (237)	–	83,191,781	80,644,532
31	Dividends Declared (238)	–		
32	Matured Long-Term Debt (239)	–		
33	Matured Interest (240)	–		
34	Tax Collections Payable (241)	–	10,676,784	11,712,705
35	Miscellaneous Current and Accrued Liabilities (242)	–	78,587,018	72,677,025
36	TOTAL Current and Accrued Liabilities *(Enter Total of lines 24 thru 35)*		530,900,439	481,252,741

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric & Power Co.	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c) (Omit Cents)	Balance at End of Year (d) (Omit Cents)
			(DOLLARS)	
37	DEFERRED CREDITS			
38	Customer Advances for Construction (252)		2,509,079	2,104,349
39	Accumulated Deferred Investment Tax Credits (255)	264	109,646,854	103,409,345
40	Deferred Gains from Disposition of Utility Plant (256)		1,434,539	1,380,659
41	Other Deferred Credits (253)	266	205,014,501	216,959,849
42	Unamortized Gain on Reacquired Debt (257)			11,180
43	Accumulated Deferred Income Taxes (281-283)	268-273	326,002,045	496,582,834
44	TOTAL Deferred Credits *(Enter Total of lines 38 thru 43)*		644,607,018	820,448,216
45	OPERATING RESERVES			
46	Property Insurance Reserve (261)		1,350,000	1,350,000
47	Injuries and Damages Reserve (262)		199,600	319,804
48	Pensions and Benefits Reserve (263)			
49	Miscellaneous Operating Reserves (265)			
50	TOTAL Operating Reserves *(Enter Total of lines 46 thru 49)*		1,549,600	1,669,804
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66				
67				
68	TOTAL Liabilities and Other Credits *(Enter Total of lines 14, 22, 36, 44 and 50)*		7,057,831,487	7,359,356,203

Name of Respondent	This Report Is	Date of Report	Year of Report
Virginia Electric & Power Co.	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, *Revenue and Expenses from Utility Plant Leased to Others,* in another utility column (i, k, m, o) in a similar manner to a utility department. Spread the amount(s) over lines 01 thru 20 as appropriate. Include these amounts in columns (c) and (d) totals.

2. Report amounts in account 414, *Other Utility Operating Income,* in the same manner as accounts 412 and 413 above.

3. Report data for lines 7, 9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1, and 407.2.

4. *Use page 122 for important notes regarding the statement of income or any account thereof.*

5. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power and gas purchases.

6. *Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from*

Line No	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME		(DOLLARS)	
2	Operating Revenues (400)		2,350,769,552	2,161,855,044
3	Operating Expenses			
4	Operation Expenses (401)		1,183,751,718	1,154,224,968
5	Maintenance Expenses (402)		169,564,299	235,146,790
6	Depreciation Expense (403)		189,133,585	173,824,000
7	Amort. & Depl. of Utility Plant (404–405)		1,807,996	277,789
8	Amort. of Utility Plant Acq. Adj. (406)		[illegible]	[illegible]
9	Amort. of Property Losses (407)		21,229,646	22,233,497
10	Amort. of Conversion Expenses (407)		-	-
11	Taxes Other Than Income Taxes (408.1)	258	134,933,542	[illegible]
12	Income Taxes – Federal (409.1)	258	(8,462,812)	14,732,464
13	– Other (409.1)	258	(46,772)	47,306
14	Provision for Deferred Inc. Taxes (410.1)	224 268 273	233,301,665	125,158,532
15	(Less) Provision for Deferred Income Taxes–Cr. (411.1)	224.258 273	61,920,438	53,933,081
16	Investment Tax Credit Adj. – Net (411.4)	264	(10,199,873)	[illegible]
17	(Less) Gains from Disp. of Utility Plant (411.6)		53,567	52,551
18	Losses from Disp. of Utility Plant (411.7)		-	
19	TOTAL Utility Operating Expenses *(Enter Total of lines 4 thru 18)*		[illegible]	[illegible]
20	Net Utility Operating Income *(Enter Total of line 2 less 19) (Carry forward to page 117, line 21)*		305,595,546	[illegible]

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric & Power Co.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

STATEMENT OF INCOME FOR THE YEAR (Continued)

settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases. State the accounting treatment accorded such refunds and furnish the necessary particulars (details), including income tax effects, so that corrections of prior Income and Retained Earnings Statements and Balance Sheets may be made if needed; or furnish amended financial statements if that be deemed more appropriate by the utility.

7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such notes may be attached at page 122.

8. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the approximate dollar effect of such changes.

9. Explain in a footnote if the previous year's figures are different from that reported in prior reports.

10. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 1 to 19, and report the information in the blank space on page 122 or in a supplemental statement.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year (e)	Previous Year (f)	Current Year (g)	Previous Year (h)	Current Year (i)	Previous Year (j)	Line No.
	(DOLLARS)					1
2,254,526,274	2,069,764,264	106,243,278	92,088,780			2
						3
1,093,098,303	1,077,225,299	92,653,415	76,999,669			4
166,588,835	136,275,495	2,975,364	1,871,295			5
186,821,341	171,760,122	2,312,244	2,063,878			6
1,803,881	274,324	4,115	3,465			7
-	-	18,408	18,408			8
21,220,648	12,203,497	-	-			9
-	-	-	-			10
130,561,325	117,432,625	4,292,217	3,430,648			11
(8,391,897)	13,192,973	(70,915)	1,539,491			12
(40,772)	47,306	-	-			13
232,448,820	124,367,743	852,865	1,790,789			14
61,447,125	52,603,254	363,313	1,329,827			15
(10,418,638)	6,136,187	308,765	575,170			16
52,260	52,260	1,620	1,620			17
-	-	-	-			18
1,752,192,461	1,606,260,057	102,981,545	86,961,366			19
502,333,813	463,504,207	3,261,733	5,127,414			20

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	OTHER UTILITY		OTHER UTILITY		OTHER UTILITY	
	Current Year (k)	Previous Year (l)	Current Year (m)	Previous Year (n)	Current Year (o)	Previous Year (p)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric & Power Co.	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Account (a)	Ref. Page No (b)	TOTAL (DOLLARS) Current Year (c)	TOTAL Previous Year (d)
21	Net Utility Operating Income *(Carried forward from page 114)*	–	505,595,546	468,631,621
22	Other Income and Deductions			
23	Other Income			
24	Nonutility Operating Income			
25	Revenues From Merchandising, Jobbing and Contract Work (415)			
26	Costs and Exp. of Merchandising, Jobbing and Contract Work (416)			
27	Revenues From Nonutility Operations (417)			
28	Expenses of Nonutility Operations (417.1)			
29	Nonoperating Rental Income (418)		265,277	(91,203)
30	Equity in Earnings of Subsidiary Companies (418.1)	–	2,604,152	331,880
31	Interest and Dividend Income (419)		3,552,685	3,782,788
32	Allowance for Other Funds Used During Construction (419.1)	–	43,863,050	44,263,501
33	Miscellaneous Nonoperating Income (421)		114,149	13,323,682
34	Gain on Disposition of Property (421.1)		21,284,473	–
35	TOTAL Other Income *(Enter Total of lines 25 thru 34)*	–	71,683,786	61,610,648
36	Other Income Deductions			
37	Loss on Disposition of Property (421.2)		441,771	141,045
38	Miscellaneous Amortization (425)	337		
39	Miscellaneous Income Deductions (426.1-426.5)	337	1,603,951	777,315
40	TOTAL Other Income Deductions *(Total of lines 37 thru 39)*	–	2,045,722	918,360
41	Taxes Applic. to Other Income and Deductions			
42	Taxes Other Than Income Taxes (408.2)	258	115,289	130,223
43	Income Taxes—Federal (409.2)	258	16,985,073	8,021,320
44	Income Taxes—Other (409.2)	258	202,432	62,685
45	Provision for Deferred Inc. Taxes (410.2)	224,268-273	(750,242)	(414,795)
46	Provision for Deferred Income Taxes—Cr. (411.2)	224,268-273	(1,458,706)	–
47	Investment Tax Credit Adj.—Net (411.5)			
48	Investment Tax Credits (420)			
49	TOTAL Taxes on Other Inc. and Ded. *(Enter Total of 42 thru 48)*	–	15,093,846	7,799,433
50	Net Other Income and Deductions *(Enter Total of lines 35, 40, 49)*	–	54,544,218	52,892,855
51	Interest Charges			
52	Interest on Long-Term Debt (427)	–	296,224,853	280,011,551
53	Amort. of Debt Disc. and Expense (428)		1,775,036	1,945,345
54	Amortization of Loss on Reacquired Debt (428.1)			
55	Amort. of Premium on Debt-Credit (429)		(72,738)	(88,398)
56	Amortization of Gain on Reacquired Debt-Credit (429.1)		(2,814,013)	(267,878)
57	Interest on Debt to Assoc. Companies (430)	337		
58	Other Interest Expense (431)	337	25,947,616	42,686,685
59	Allowance for Borrowed Funds Used During Construction-Credit (432)	–	(39,510,148)	(40,542,770)
60	Net Interest Charges *(Enter Total of lines 52 thru 59)*	–	281,550,606	283,744,535
61	Income Before Extraordinary Items *(Enter Total of lines 21, 50 and 60)*	–	278,589,158	237,779,941
62	Extraordinary Items			
63	Extraordinary Income (434)			
64	Extraordinary Deductions (435)			
65	Net Extraordinary Items *(Enter Total of line 63 less line 64)*	–		
66	Income Taxes—Federal and Other (409.3)	258		
67	Extraordinary Items After Taxes *(Enter Total of line 65 less line 66)*	–		
68	Net Income *(Enter Total of lines 61 and 67)*		278,589,158	237,779,941

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric & Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1982

STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
3. State the purpose and amount for each reservation or appropriation of retained earnings.
4. List first Account 439, *Adjustments to Retained Earnings*, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
5. Show dividends for each class and series of capital stock.
6. Show separately the state and federal income tax effect of items shown for Account 439, *Adjustments to Retained Earnings*.
7. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
8. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance – Beginning of Year		$470,838,563
2	Changes (*Identify by prescribed retained earnings accounts*)		
3	Adjustments to Retained Earnings (Account 439)		
4	Credit:		
5	Credit:		
6	Credit:		
7	Credit:		
8	Credit:		
9	TOTAL Credits to Retained Earnings (Account 439) (*Enter Total of lines 4 thru 8*)		$ -0-
10	Debit:		
11	Debit:		
12	Debit: See (1) on page 122		503,927
13	Debit:		
14	Debit:		
15	TOTAL Debits to Retained Earnings (Account 439) (*Enter Total of lines 10 thru 14*)		$ 503,927
16	Balance Transferred from Income (Account 433 less Account 418.1)		$278,589,158
17	Appropriations of Retained Earnings (Account 436)		
18			
19			
20			
21			
22	TOTAL Appropriations of Retained Earnings (Account 436) (*Enter Total of lines 18 thru 21*)		$ -0-
23	Dividends Declared – Preferred Stock (Account 437)		
24	Dividends Declared - Preferred Stock*		$ 50,035,808
25	Dividends Declared - Preference Stock*		6,960,006
26			
27	*See (2) on page 123		
28			
29	TOTAL Dividends Declared–Preferred Stock (Account 437) (*Enter Total of lines 24 thru 28*)		$ 56,995,814
30	Dividends Declared – Common Stock (Account 438)		
31	$1.525 per share		$172,790,650
32			
33			
34			
35			
36	TOTAL Dividends Declared–Common Stock (Account 438) (*Enter Total of lines 31 thru 35*)		$172,790,650
37	Transfers from Acct. 216.1, Unappropriated Undistributed Subsidiary Earnings		
38	Balance – End of Year (*Enter Total of lines 01, 09, 15, 16, 22, 29, 36 and 37*)		$519,137,330

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric & Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

STATEMENT OF RETAINED EARNINGS FOR THE YEAR (Continued)

Line No.	Item (a)	Amount (b)
	APPROPRIATED RETAINED EARNINGS (Account 215) State balance and purpose of each appropriated retained earnings amount at end of year and give accounting entries for any applications of appropriated retained earnings during the year.	
39		
40		
41		
42		
43		
44		
45	TOTAL Appropriated Retained Earnings (Account 215)	$ -0-
	APPROPRIATED RETAINED EARNINGS-AMORTIZATION RESERVE, FEDERAL (Account 215.1) State below the total amount set aside through appropriations of retained earnings, as of the end of the year, in compliance with the provisions of Federally granted hydroelectric project licenses held by the respondent. If any reductions or changes other than the normal annual credits hereto have been made during the year, explain such items in a footnote	
46	TOTAL Appropriated Retained Earnings-Amortization Reserve, Federal (Account 215.1)	$ 49,449
47	TOTAL Appropriated Retained Earnings (Accounts 215, 215.1)	$ 49,449
48	TOTAL Retained Earnings (Account 215, 215.1, 216)	$519,186,779
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)	
49	Balance – Beginning of Year (Debit or Credit)	
50	Equity in Earnings for Year (Credit) (Account 418.1)	
51	Dividends Received (Debit)	
52	Other Changes *(Explain)*	
53	Balance – End of Year	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric & Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1982

STATEMENT OF CHANGES IN FINANCIAL POSITION

1. This statement is not restricted to those items which are noncurrent in nature. It is intended that this statement be flexible enough in nature so that latitude can be given, under the classification of "Other," to allow for disclosure of all significant changes and transactions, whether they are within or without the current asset and liability groups.

2. If the notes to the funds statement in the respondent's annual report to stockholders are applicable in every respect to this statement, such notes should be attached to page 122.

3. Under "Other" specify significant amounts and group others.

4. Codes Used:
   (a) Such as net increase-decrease in working capital, etc., other than changes in short term investments shown as item 4(e).
   (b) Bonds, debentures and other long term debt
   (c) Net proceeds or payments.
   (d) Include commercial paper.
   (e) Identify separately such items as investments, fixed assets, intangibles, etc

5. Enter on page 122 clarifications and explanations.

Line No	SOURCES OF FUNDS *(See instructions for explanation of codes)* (a)	Amounts (b)
1	Funds from Operations	
2	Net Income	$ 278,589,158
3	Principal Non-Cash Charges (Credits) to Income	
4	Depreciation and Depletion	189,133,585
5	Amortization of *(Specify)* (2)	83,665,004
6	Provision for Deferred or Future Income Taxes (Net)	171,491,247
7	Investment Tax Credit Adjustments	(10,109,873)
8	Less Allowance for Other Funds Used During Construction	43,863,050
9	Other (Net)-Gain (pretax) on Sale of a Portion of the Bath Co.	
10	Pumped Storage Project	[illegible]
11	Less Allowance for Borrowed Funds Used During Construction	39,510,148
12		
13		
14		
15	TOTAL Funds from Operations *(Enter Total of lines 2 thru 14)*	612,872,953
16	Funds from Outside Sources (New Money)	
17	Long-Term Debt (b) (c)	156,850,000
18	Preferred Stock (c)	
19	Common Stock (c)	187,920,288
20	Net Increase in Short-Term Debt (d)	
21	Other (Net)	
22	Decrease in Deferred Fuel Costs	13,764,653
23	Pollution Control Project Funds	15,517,460
24		
25	Sale of Portion of Bath County Pumped Storage Project	
26	(includes option payments)	198,216,731
27	TOTAL Funds from Outside Sources *(Enter Total of lines 17 thru 26)*	572,269,132
28	Sale of Non-Current Assets (e)	
29		
30	Contributions from Associated and Subsidiary Companies	
31	Other (Net) (a)	
32		
33		
34		
35		
36		
37	TOTAL Sources of Funds *(Enter Total of lines 15, 27, 28 thru 36)*	$1,185,142,085

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric & Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

STATEMENT OF CHANGES IN FINANCIAL POSITION (Continued)

Line No.	APPLICATION OF FUNDS (a)	Amounts (b)
38	Construction and Plant Expenditures (Including Land)	
39	Gross Additions to Utility Plant (Less Nuclear Fuel)	$ 663,493,385
40	Gross Additions to Nuclear Fuel	41,305,309
41	Gross Additions to Common Utility Plant	6,172,538
42	Gross Additions to Nonutility Plant	
43	Less Allowance for Funds Used During Construction	83,373,198
44	Other Net Cost of Removal (Retirements)	(6,616,871)
45	TOTAL Applications to Construction and Plant Expenditures (Including Land) *(Enter Total of lines 38 thru 44)*	620,981,163
46	Dividends on Preferred Stock and Preference	56,995,814
47	Dividends on Common Stock	172,790,650
48	Funds for Retirement of Securities and Short-Term Debt	
49	Long-term Debt (b) (c)	215,216,000
50	Preferred Stock (c)	1,983,400
51	Redemption of Capital Stock	
52	Net Decrease in Short-term Debt (d)	
53	Other (Net)	
54	Decrease in Loans Payable	61,605,000
55		
56	Abandoned Project Costs	13,253,265
57		
58	Purchase of Other Non-Current Assets (e)	
59		
60		
61	Investments in and Advances to Associated and Subsidiary Companies	(25,274)
62	Other (Net) (a):	
63	Decrease in Uranium Settlement	2,791,633
64	Decrease in Working Capital other than Loans Payable (3)	(4,670,125)
65	Increase in Deferred Interest	6,587,585
66	Increase in Nuclear Fuel Progress Payments	27,263,644
67	Other, Net	10,369,330
68	TOTAL Applications of Funds *(Enter Total of lines 45 thru 67)*	$1,185,142,085

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric & Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Changes in Financial Position, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.

2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.

3. For Account 116, *Utility Plant Adjustments*, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.

4. Where Accounts 189, *Unamortized Loss on Reacquired Debt*, and 257, *Unamortized Gain on Reacquired Debt*, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform Systems of Accounts.

5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.

6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be attached hereto.

Notes to Balance Sheet:

(1) Refer to Notes to Financial Statements, pages 26-35 in the Company's 1982 Annual Report to Stockholders attached, which notes are incorporated herein by reference.

Notes to Income Statement:

(1) Refer to notes to Financial Statements, pages 26-35 in the Company's 1982 Annual Report to Stockholders attached, which notes are incorporated herein by reference.

Notes to Statement of Retained Earnings for the Year:

Detail of Line 15, page 118:

(1) Debits to Retained Earnings

Charge-off of capital stock expenses incurred in connection with issuance of:

5,500,000 shares of No Par Value Common Stock, February 1982	$168,903
2,604,301 shares of No Par Value Common Stock through the Automatic Dividend Reinvestment Plan in 1982	319,983
792,630 shares of No Par Value Common Stock through the Employee Savings Plan in 1982	14,575
Adjustment - Dividends	466
Total Charge-off of capital stock expense	$503,927

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 82

NOTES TO FINANCIAL STATEMENTS (Continued)

Notes to Statement of Retained Earnings for the Year (Cont'd.):

Detail of Line 29, page 118:

(2) Dividends Declared - Preferred Stock

Class		Dividend Per Share		
$5.00	Dividend	$5.00		$ 533,384
$4.04	Dividend	4.04		52,220
$4.20	Dividend	4.20		62,148
$4.12	Dividend	4.12		134,040
$4.80	Dividend	4.80		351,388
$7.72	Dividend	7.72		2,702,000
$8.84	Dividend	8.84		3,094,000
$7.45	Dividend	7.45		2,980,006
$7.20	Dividend	7.20		3,240,000
$7.72	Dividend	7.72		3,860,000
$7.325	Dividend	7.325		5,127,500
$8.40	Dividend	8.40		6,720,000
$9.75	Dividend	9.75		5,850,018
$9.125	Dividend	9.125		1,733,750
$8.20	Dividend	8.20		4,920,000
$8.60	Dividend	8.60		2,985,096
$8.625	Dividend	8.625		3,191,258
$8.925	Dividend	8.925		2,499,000
			Total Preferred	50,035,808

Dividends Declared - Preference Stock

$2.90	Dividend	2.90		6,960,006
			Total Preferred and Preference	$56,995,814

(3) Refer to Notes to Financial Statements, pages 26-35 in the Company's 1982 Annual Report to Stockholders attached, which notes are incorporated herein by reference.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric & Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1982

NOTES TO FINANCIAL STATEMENTS (Continued)

Notes to Statement of Changes in Financial Position:

(1) Refer to Notes to Financial Statements, pages 26-35, in the Company's Annual Report to Stockholders attached, which notes are incorporated herein by reference.

(2) Includes amortization of:

Common Utility Plant	$ 1,807,996
Utility Plant Acquisition Adjustment	16,408
Abandoned Project Costs	21,220,648
Nuclear Fuel	60,617,952
	$ 83,665,004

(3) Changes in individual amounts comprising working capital other than loans payable were as follows:

Accounts Receivable	$ 4,224,742
Accrued Unbilled Revenues	(11,012,105)
Materials and Supplies	22,801,426
Accounts Payable, Trade	(12,652,113)
Due to Banks	(6,973,172)
Taxes Accrued	5,670,330
Interest Accrued	2,547,249
Deferred Income Taxes	2,786,921
Other, Net	(2,362,395)
	$ (4,673,125)

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Line No.	Item (a)	Total ($) (b)	Electric ($) (c)	Gas ($) (d)	Other (Specify) ____ (e)	Other (Specify) ____ (f)	Common ($) (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (Classified)	4,862,919,409	4,773,627,639	75,452,423			13,839,347
4	Plant Purchased or Sold	-0-					
5	Completed Construction not Classified	1026,662,889	1014,428,604	7,938,598			4,295,687
6	Experimental Plant Unclassified	-0-					
7	TOTAL (Enter Total of lines 3 thru 6)	5889,582,298	5788,056,243	83,391,021			18,135,034
8	Leased to Others	-0-					
9	Held for Future Use	711,068	711,068				
10	Construction Work in Progress	1,196,296,767	1,191,037,212	1,474,226			3,785,329
11	Acquisition Adjustments	276,154		276,154			
12	TOTAL Utility Plant (Enter Total of lines 7 thru 11)	7086,866,287	6979,804,523	85,141,401			21,920,363
13	Accum. Prov. for Depr., Amort., & Depl.	1421,849,007	1,391,677,969	24,837,992			5,333,046
14	Net Utility Plant Less Nuclear Fuel (Enter Total of line 12 less 13)	5665,017,280	5588,126,554	60,303,409			16,587,317
15	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
16	In Service						
17	Depreciation (a)	1,440,180,135	1410,581,904	24,594,052			5,004,179
18	Amort. and Depl. of Producing Natural Gas Land and Land Rights						
19	Amort. of Underground Storage Land and Land Rights						
20	Amort. of Other Utility Plant (b)	(18,575,068)	(18,903,935)				328,867
21	TOTAL In Service (Enter Total of lines 17 thru 20)	1421,605,067	1,391,677,969	24,594,052			5,333,046
22	Leased to Others						
23	Depreciation						
24	Amortization and Depletion						
25	TOTAL Leased to Others (Enter Total of lines 23 and 24)						
26	Held for Future Use						
27	Depreciation						
28	Amortization						
29	TOTAL Held for Future Use (Enter Total of lines 27 and 28)						
30	Abandonment of Leases (Natural Gas)						
31	Amort. of Plant Acquisition Adj.	243,940		243,940			
32	TOTAL Accumulated Provisions (Should agree with line 13 above) (Enter Total of lines 21, 25, 29, 30, and 31)	1421,849,007	1,391,677,969	24,837,992			5,333,046

(a) Allocated based on depreciable plant in service.
(b) Amortization of Limited Term Electric and Gas Plant (Accounts 404 and 404.1) and $20,788,399 adjusted from Accumulated Depreciation to Provision for Amortization for Surry Steam Generators.

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

NUCLEAR FUEL MATERIALS (Accounts 120.1 through 120.5 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling, owned by the respondent.

2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of Item (a)	Balance Beginning of Year (b)	Changes During Year: Additions (c)	Changes During Year: Amortization (d)	Changes During Year: Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in Process of Refinement, Conversion, Enrichment & Fabrication (120.1)					
2	Fabrication	$ 4,356,428	$12,053,754		-	$ 16,410,182
3	Nuclear Materials	85,304,609	47,021,778		-	132,326,387
4	Allowance for Funds Used during Construction	285,812	2,781,200		-	3,067,012
5	Other Overhead Construction Costs	61,986	275,578		-	337,564
6	SUBTOTAL *(Enter Total of lines 2 thru 5)*	90,008,835				152,141,145
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)	87,475,257	30,855,064		(A)56,523,838	61,806,483
9	In Reactor (120.3)	143,538,072	5,499,021		(B)48,787,936	100,249,157
10	SUBTOTAL *(Enter Total of lines 8 and 9)*	231,013,329				162,055,640
11	Spent Nuclear Fuel (120.4)	35,195,717	48,787,936		(C) 657,248	83,326,405
12	Less Accum. Prov. for Amortization of Nuclear Fuel Assemblies (120.5)	210,878,606		60,617,952		271,496,558
13	TOTAL Nuclear Fuel Stock *(Enter Total of lines 6, 10, and 11 less line 12)*	145,339,275				126,026,632
14	Estimated Net Salvage Value of Nuclear Materials in line 9	(42,944,394)				(44,698,258)
15	Estimated Net Salvage Value of Nuclear Materials in line 11	(158,086,796)				(186,795,069)
16	Estimated Net Salvage Value of Nuclear Materials in Chemical Processing					
17	Nuclear Materials Held for Sale (157)					
18	Uranium					
19	Plutonium					
20	Other					
21	TOTAL Nuclear Materials Held for Sale *(Enter Total of lines 18, 19, and 20)*					

EXPLANATION OF OTHER REDUCTIONS

(A) Reductions indicate the transfer of Surry 2 Batches 4A5, 6A2 from 120.2 to 120.3; 9 from 120.2 to 186.0; Surry 1 Batches 9A, 9B from 120.2 to 186 and 120.1; and North Anna 2 Batch 5 from 120.2 to 120.1

(B) Reductions indicate the transfer of Surry 2, Batches 5A, 6A1, 6B1; North Anna 1 Batches 1A3, 3A2, 4A and North Anna Batches 1A1 and 2A1 from 120.3 to 120.4

(C) Reductions indicate the transfer of North Anna 2 Batch 3A3 from 120.4 to 120.3

NUCLEAR FUEL MATERIAL - LEASED
RESPONSE TO INSTRUCTION 2 - PAGE 201
FERC FORM 1

	Surry Unit 1	Surry Unit 2
A. Nuclear Fuel Materials Leased		
Balance beginning of year 01/01/82		
In Reactor	$55,675,800	$20,269,195
Other	-0-	22,985,171
Total	55,675,800	43,254,366
Plus: 1982 Additions to lease (1)	29,168,409	26,883,383
Less: 1983 Buy-Back of Fuel	3,365,900	-0-
Net Additions to Lease	25,802,509	26,883,383
Less: Nuclear Fuel Burn-up Expenses (2)		
(1) Fuel burned in 1981 paid in 1982	7,075,731	-0-
(2) Fuel burned in 1982	27,003,202	30,504,071
(3) Less: Fuel burned in 1982 to be paid in 1983	5,144,801	2,789,869
Total Nuclear Fuel Burn	28,934,132	27,714,202
Less: Amortization due to rear-end values (net reprocessing and permanent disposal) (3)		
(1) Rear-end Values - 1981 amortized in 1982	1,313,878	-0-
(2) Rear-end Values 1982	5,242,313	3,417,521
(3) Less: Rear-end Values - 1982 to be amortized in 1983	778,457	41,431
Total Rear-end Amortization	5,777,734	3,376,090
Net payments to lessor - fuel (4)	23,156,398	24,338,112
Balance, end of year 12/31/82		
In Reactor	30,914,833	41,105,182
Other	27,407,078	4,694,455
Total	$58,321,911	$45,799,637
B. 1982 Lease Costs for Nuclear Fuel (4)		
Interest and Fees	$7,311,614	$6,143,666

(1) Nuclear Fuel in process of refinement, conversion, enrichment and fabrication (includes capitalized lease charges).

(2) Does not include credit for Westinghouse Uranium Settlement.

(3) Includes rear end values expensed to FERC Account No. 253. SN-1 $177,090 and SN-2 $33,287.

(4) Reflects actual cash payments to lessors and their agents during 1982 in connection with various lease agreements.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec 31, 19 82

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, *Electric Plant in Service (Classified)*, this page and the next include Account 102, *Electric Plant Purchased or Sold;* Account 103, *Experimental Electric Plant Unclassified;* and Account 106, *Completed Construction Not Classified-- Electric.*
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such amounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at

(Continued on page 204)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization	$	$	$	$	$ 80,000	$ 80,000
3	(302) Franchises and Consents	12,820					12,820
4	(303) Miscellaneous Intangible Plant	8,478,975					8,478,975
5	TOTAL Intangible Plant *(Enter Total of lines 2, 3, and 4)*	8,491,795				80,000	8,571,795
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	2,877,286		2,136			2,875,150
9	(311) Structures and Improvements	144,339,335	7,835,013	641,144	(11,979)	48,140	151,569,365
10	(312) Boiler Plant Equipment	590,875,930	75,283,528	1,488,055	(6119,661)		658,551,742
11	(313) Engines and Engine Driven Generators						
12	(314) Turbogenerator Units	283,863,355	7,543,793	2,665,305	11,852		288,753,695
13	(315) Accessory Electric Equipment	74,344,064	8,777,010	10,254	2,769		83,113,589
14	(316) Misc. Power Plant Equipment	17,168,528	314,948	611,550	(29,183)	65,597	17,388,340
15	TOTAL Steam Production Plant *(Enter Total of lines 8 thru 14)*	1113,468,498	10025[illegible]292	5,418,444	(146,202)	93,737	1202,251,881
16	B. Nuclear Production Plant						
17	(320) Land and Land Rights	37,247,583	(74,217)	428,826			36,744,540
18	(321) Structures and Improvements	441,903,316	45,310,980	43,858	1,223		487,171,661
19	(322) Reactor Plant Equipment	998,386,497	12,487,671	8,472,813	562		1002,401,917
20	(323) Turbogenerator Units	260,649,406	28,210,020				288,859,426
21	(324) Accessory Electric Equipment	336,994,666	2,339,390		24,131	104	339,358,291
22	(325) Misc. Power Plant Equipment	43,994,645	843,754	69,158	(25,916)	(4,521)	44,738,804
23	TOTAL Nuclear Production Plant *(Enter Total of lines 17 thru 22)*	2119,176,113	89,117,598	9,014,655		(4,417)	2199,274,639
24	C. Hydraulic Production Plant						
25	(330) Land and Land Rights	9,653,629				144,083	9,797,712
26	(331) Structures and Improvements	3,836,908				254,618	4,091,526
27	(332) Reservoirs, Dams, and Waterways	45,263,372				123,239	45,386,611
28	(333) Water Wheels, Turbines, and Generators	14,447,653					14,447,653
29	(334) Accessory Electric Equipment	1,699,744	35,369				1,735,113
30	(335) Misc. Power Plant Equipment	767,615	14,848				782,463
31	(336) Roads, Railroads, and Bridges	121,104					121,104
32	TOTAL Hydraulic Production Plant *(Enter Total of lines 25 thru 31)*	75,790,025	50,217			521,940	76,362,182

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
33	D. Other Production Plant						
34	(340) Land and Land Rights	$ 21,057	$	$	$	$	$ 21,057
35	(341) Structures and Improvements	348,068					348,068
36	(342) Fuel Holders, Products, and Accessories	175,182					175,182
37	(343) Prime Movers	544,833	5,946				550,779
38	(344) Generators	2,200,922	7,838				2,208,760
39	(345) Accessory Electric Equipment	237,685	69,085				306,770
40	(346) Misc. Power Plant Equipment	196,894					196,894
41	TOTAL Other Production Plant *(Enter Total of lines 34 thru 40)*	3,724,641	82,869				3,807,510
42	TOTAL Production Plant *(Enter Total of lines 15, 23, 32, and 41)*	3,312,159,277	189,504,976	14,433,099	(6,146,202)	611,260	3,481,696,212
43	3. TRANSMISSION PLANT						
44	(350) Land and Land Rights	63,237,234	12,055,182	743,534		(50,941)	74,497,941
45	(352) Structures and Improvements	4,784,158	(2,847,320)	33,379	2,455,461		4,358,920
46	(353) Station Equipment	190,673,964	39,194,758	3,338,861	(2,510,293)	7,600	224,027,168
47	(354) Towers and Fixtures	141,355,834	3,512,685	129,896		18,564	144,757,187
48	(355) Poles and Fixtures	93,093,323	18,565,503	1,321,647		4,120	110,341,299
49	(356) Overhead Conductors and Devices	107,653,579	17,973,862	817,265			124,810,176
50	(357) Underground Conduit	3,857,579	(1,821,395)				2,036,184
51	(358) Underground Conductors and Devices	1,525,738					1,525,738
52	(359) Roads and Trails	118,488	11,362				129,850
53	TOTAL Transmission Plant *(Enter Total of of lines 44 thru 52)*	606,299,897	86,644,637	6,384,582	(54,832)	(20,657)	686,484,463
54	4. DISTRIBUTION PLANT						
55	(360) Land and Land Rights	18,014,912	907,042	99,000		(26,849)	18,796,105
56	(361) Structures and Improvements	2,836,261	15,546	9,015	3,217,491		6,060,283
57	(362) Station Equipment	179,982,378	8,591,277	1,138,501	(3,217,260)	180,401	184,398,295
58	(363) Storage Battery Equipment						
59	(364) Poles, Towers, and Fixtures	195,637,389	10,581,844	2,470,104		8,179	203,757,308
60	(365) Overhead Conductors and Devices	214,218,665	16,423,491	3,170,717		(47,914)	227,423,525
61	(366) Underground Conduit	32,333,913	2,545,837	21,835		564	34,858,479
62	(367) Underground Conductors and Devices	164,886,474	15,593,132	805,764		5,842	179,679,684
63	(368) Line Transformers	292,986,041	19,725,760	5,712,746	54,601	(113,064)	306,940,592
64	(369) Services	173,621,379	15,478,482	928,861		(9,027)	188,161,973
65	(370) Meters	73,117,202	9,987,646	1,091,322		(11,857)	82,001,669
66	(371) Installations on Customer Premises	165,355	1,575,699				1,741,054

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
67	(372) Leased Property on Customer Premises	$	$	$	$	$	$
68	(373) Street Lighting and Signal Systems	56,912,672	2,732,315	898,654		(8,397)	58,737,936
69	TOTAL Distribution Plant *(Enter Total of lines 55 thru 68)*	1,404,712,641	104,153,071	16,346,519	54,832	(22,122)	1,492,556,903
70	5. GENERAL PLANT						
71	(389) Land and Land Rights	3,765,612	54,870			973,310	4,793,792
72	(390) Structures and Improvements	20,036,564	1,524,005	24,567		4,907,304	26,495,386
73	(391) Office Furniture and Equipment	9,420,162	7,700,680		254,314	823,482	18,198,638
74	(392) Transportation Equipment	30,877,230	8,962,868	317,971			39,522,127
75	(393) Stores Equipment	4,046,782	236,644		211,155	(48,140)	4,496,441
76	(394) Tools, Shop and Garage Equipment	4,518,648	338,127		(470,803)	(25,166)	4,360,806
77	(395) Laboratory Equipment	4,161,306	462,275		(23,720)	(889)	4,599,272
78	(396) Power Operated Equipment	2,473,414	1,271,915		14,083		3,759,412
79	(397) Communication Equipment	8,420,566	1,413,933	616	65,400	235,176	10,134,459
80	(398) Miscellaneous Equipment	1,331,306	215,812		(30,533)	76,001	1,593,086
81	SUBTOTAL *(Enter Total of lines 71 thru 80)*	89,104,390	22,231,209	343,154	19,896	6,946,078	117,958,419
82	(399) Other Tangible Property *	798,210	(64)		(9,695)		788,451
83	TOTAL General Plant *(Enter Total of lines 81 and 82)*	89,902,600	22,231,145	343,154	10,201	6,946,078	118,746,870
84	TOTAL (Accounts 101 and 106)	5,421,566,210	402,538,829	37,507,354	(6,136,001)	7,594,559	5,788,056,243
85	(102) Electric Plant Purchased *(See Instr. 8)*						
86	(102) Electric Plant Sold *(See Instr. 8)* **				(3,867,271)	3,867,271	
87	(103) Experimental Electric Plant Unclassified						
88	TOTAL Electric Plant in Service	5,421,566,210	402,538,829	37,507,354	(10,003,272)	11,461,830	5,788,056,243

*Account 399 includes coal properties located adjacent to the Company's mine-mouth Mt. Storm Power Station in Grant County, West Virginia and various pieces of miscellaneous equipment.

**Account 102-amounts in columns (e) and (f) represent entries recorded covering the sale of transmission and distribution facilities to Carolina Power and Light Company and the Greenville Utility Commission on December 10, 1982. Copies of journal entries were filed with the Federal Energy Regulatory Commission on February 9, 1983.

COMPLETED CONSTRUCTION NOT CLASSIFIED - ACCOUNT 106

Each month the Company transfers the costs of projects in service at the end of the month, for which final costs have not been made, from Account 107-Construction Work in Progress to Account 106-Completed Construction Not Classified. These costs are classified to appropriate primary accounts on a tentative basis pending final classification of all costs to the projects. As each such project is closed, the amounts carried in Account 106 are reversed and final costs are recorded in the appropriate primary accounts for Electric Plant in Service.

The following schedule shows the amounts included on Pages 202, 203, and 204 representing Completed Construction Not Classified.

Account	Description	Balance 12/31/81	Balance 12/31/82	Net Change
	Production Plant			
	Steam Production Plant			
310	Land and Land Rights	$ 67,466	$ 67,466	$ -0-
311	Structures and Improvements	26,959,295	19,987,185	(6,972,110)
312	Boiler Plant Equipment	48,975,942	115,213,302	66,237,360
314	Turbogenerator Units	18,428,942	24,705,265	6,276,323
315	Accessory Electric Equipment	3,482,998	11,112,368	7,629,370
316	Miscellaneous Power Plant Equipment	1,737,884	2,146,741	408,857
	Total Steam Production Plant	99,652,527	173,232,327	73,579,800
	Nuclear Production Plant			
320	Land and Land Rights	96,021	1,846	(94,175)
321	Structures and Improvements	151,330,044	116,869,061	(34,460,983)
322	Reactor Plant Equipment	560,081,627	309,988,093	(250,093,534)
323	Turbogenerator Units	100,129,967	60,177,026	(39,952,941)
324	Accessory Electric Equipment	125,247,408	13,513,487	(111,733,921)
325	Miscellaneous Power Plant Equipment	14,871,171	8,403,029	(6,468,142)
	Total Nuclear Production Plant	951,756,238	508,952,542	(442,803,696)
	Hydraulic Production			
332	Reservoirs, Dams and Waterways	57,581	-0-	(57,581)
334	Accessory Electric Equipment	245,727	281,096	35,369
	Total Hydraulic Production Plant	303,308	281,096	(22,212)
	Other Production Plant			
340	Land and Land Rights	-0-	-0-	-0-
341	Structures and Improvements	-0-	-0-	-0-
342	Fuel Holders, Producers and Accessories	-0-	-0-	-0-
343	Prime Movers	280,685	133,890	(146,795)
344	Generators	241,237	249,075	7,838
345	Accessory Electric Equipment	-0-	69,085	69,085
346	Miscellanous Power Plant Equipment	-0-	-0-	-0-
	Total Other Production Plant	521,922	452,050	(69,872)
	Total Production Plant	$1,052,233,995	$ 682,918,015	$ (369,315,980)

COMPLETED CONSTRUCTION NOT CLASSIFIED - ACCOUNT 106
(Continued)

Account	Description	Balance 12/31/81	Balance 12/31/82	Net Change
	Transmission Plant			
350	Land and Land Rights	$ 18,184,204	$ 30,183,625	$ 11,999,421
352	Structures and Improvements	3,223,439	376,119	(2,847,320)
353	Station Equipment	37,624,671	74,157,428	36,532,757
354	Towers and Fixtures	47,181,004	50,697,859	3,516,855
355	Poles and Fixtures	30,020,304	47,596,881	17,576,577
356	Overhead Conductors and Devices	20,572,129	38,103,033	17,530,904
357	Underground Conduit	1,821,395	-0-	(1,821,395)
358	Underground Conductors and Devices	-0-	-0-	-0-
359	Roads and Trails	71,265	82,627	11,362
	Total Transmission Plant	158,698,411	241,197,572	82,499,161
	Distribution Plant			
360	Land and Land Rights	299,196	1,136,911	837,715
361	Structures and Improvements	689,134	693,694	4,560
362	Station Equipment	19,288,514	26,502,617	7,214,103
364	Poles, Towers and Fixtures	6,551,813	6,441,663	(110,150)
365	Overhead Conductors and Devices	8,358,846	11,511,962	3,153,116
366	Underground Conduit	2,575,053	3,013,960	438,907
367	Underground Conductors and Devices	5,133,403	6,120,565	987,162
368	Line Transformers	2,329,417	4,631,565	2,302,148
369	Services	345,980	175,696	(170,284)
370	Meters	-0-	5,216,545	5,216,545
373	Street Lighting and Signal Systems	(4,152)	77,197	81,349
	Total Distribution Plant	45,567,204	65,522,375	19,955,171
	General Plant			
389	Land and Land Rights	2,795,648	2,808,639	12,991
390	Structures and Improvements	7,333,622	8,107,328	773,706
391	Office Furniture and Equipment	2,352,627	6,470,083	4,117,456
392	Transportation Equipment	-0-	-0-	-0-
393	Stores Equipment	11,244	-0-	(11,244)
394	Tools, Shop and Garage Equipment	14,934	122,767	107.833
395	Laboratory Equipment	-0-	-0-	-0-
397	Communication Equipment	5,672,843	6,963,955	1,291,112
398	Miscellaneous Equipment	9,743	9,743	-0-
399	Other Tangible Property Other Than Coal	308,191	308,127	(64)
	Total General Plant	18,498,852	24,790,642	6,291,790
	Total Account 106 Electric Plant	$1,274,998,462	$1,014,428,604	$ (260,569,858)

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

1. Report below the information called for concerning electric plant leased to others.

2. In column (c) give the date of Commission authorization of the lease of electric plant to others.

Line No.	Name of Lessee (Designate associated companies with an asterisk) (a)	Descripton of Property Leased (b)	Commission Author-ization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2		NONE			
3					
4					
5					
6					
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42					
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44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	Land and Land Rights:			
2	Minor Items Having a Book Value of less than			
3	$250,000			$621,590
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Other Property:			
21	Minor Items Having a Book Value of less than			
22	$250,000			$ 89,478
23				
24				
25				
26				
27				
28				
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30				
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41				
42				
43				
44				
45				
46				
47	TOTAL			$711,068

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

CONSTRUCTION WORK IN PROGRESS—ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress — Electric (Account 107) (b)
	Virginia	
1	Plant Improvement $25,000 Limit - Surry	$ 926,460
2	Plant Improvement $25,000 Limit - North Anna	1,432,625
3	Plant Improvement $25,000 Limit - Bremo	333,868
4	Plant Improvement $25,000 Limit - Chesterfield	1,224,939
5	Plant Improvement $25,000 Limit - Portsmouth	641,273
6	Plant Improvement $25,000 Limit - Possum Point	1,475,195
7	Plant Improvement $25,000 Limit - Yorktown	841,661
8	Plant Improvement $25,000 Limit Combustion Turbine	208,973
9	Plant Improvement $25,000 Limit - Fossil & Hydro System	
10	Office	143,200
11	Surry - Radwaste Modification	142,984
12	Surry - Containment Inst. Air System Mod.	1,096,579
13	Chesterfield - Air Compressors	1,412,955
14	North Anna Multi-Channel Analyzer	123,584
15	North Anna #1 Steam Generator Recirculation	2,780,618
16	Surry Nuclear Fuel Handling Equipment	135,019
17	Surry ORS & LHSI Pump Mod.	139,456
18		661,207
19	Yorktown #3 Burner Management System	113,486
20	Yorktown 15 Ton Portable Crane	155,299
21	Surry-Automatic Extraction System Shutoff	349,524
22	Surry 1&2 Emergency Bus Loadcenter Add.	2,626,067
23	Chesterfield-High Pressure Rotor For Unit #5	296,764
24	Surry-SAF Relat Elec. Equip. RPL	1,368,245
25	North Anna TMI Short Term Modifications	1,277,625
26	Surry #1&2 TMI Short Term Mod.	237,214
27	Chesterfield Coal Yard Bulldozer	568,605
28	Chesterfield NPDES Pumping Station	205,569
29	Portsmouth Carbon Filter System	154,214
30	Possum Point Station Lighting	1,396,213
31	Yorktown #1 Coal Conversion	138,852
32	Yorktown Lighting Improvement	3,816,122
33	North Anna Incr. Range Radiation Monitors - TMI	2,613,173
34	North Anna Containment Accident Monitors - TMI	180,460
35	North Anna 1 Protect Elec. Penetration Mod.	175,141
36	Surry HP HTR Pump Motor	131,425
37	Surry 1&2 Instru. Detect Core Cooling - TMI	124,264
38	Surry Ser. & Instr. Air Compressor	130,266
39	Yorktown-Steam Air Heater Retubing Unit 1	315,820
40	Possum Pt. - Rebuilding Coal Yard RR Track	146,971
41	Possum Pt. - Coal Sampling Equipment	205,843
42	North Anna Spare Rod Cluster Control Assembly	227,207
43	Possum Pt. Terex 82-50 Dozer	
44		
45		
46	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 82

CONSTRUCTION WORK IN PROGRESS—ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress—Electric (Account 107) (b)
	Virginia (Cont'd)	
1	North Anna-Interim Control Room Design Modification	$ 1,203,992
2	Yorktown 1&2 Economizer Tube	420,672
3	York Waterboxes	282,873
4	York Air Preheater Basket	109,840
5	York 2 Waterboxes	403,686
6	System Maint. Support Group Equipment & Tools	2,119,414
7	Port. #1 Reserve Shutdown	147,942
8	Port. #2 Reserve Shutdown	108,036
9	Possum Point Coal Yard Dust Suppression	131,329
10	Possum Point 4 Precip. Retrofit	435,045
11	Possum Point Bunker Dust Supression	114,763
12	North Anna 1 ESF Circuit	140,766
13	Portsmouth Coal Yard Dozer and Blades	173,618
14	Chesterfield 5 Turbine Diaphram	908,346
15	Bremo Coal Sample & Analysis System	196,592
16	Chesterfield #6 BCP Seal	280,834
17	Chesterfield #5 BCP Motor	1,753,418
18	Chesterfield #5 Power Ignition System	808,321
19	Chesterfield 6 Repl. Instrumentation	1,691,675
20	Chesterfield Shift Supervisors Office	117,055
21	Unit #6 Computer Rpl.	441,955
22	Chesterfield #6 Steam Line Pipe Snubbers	190,216
23	Portsmouth Water Study	322,302
24	Ports. #3 Preheater Baskets	235,468
25	Possum Point Employee Parking Lot	193,341
26	Possum Point #4 Turbine Rotor	1,738,211
27	Possum Point UG Fire Protection	219,654
28	Yorktown 1-2 Leeds & Northrup Recorder	191,175
29	Yorktown Test Equip.	112,273
30	Possum Point 5 Brine Heater Retubing	126,015
31	PCB Contaminated Oil Disposal System	112,526
32	Possum Point #5 Flash Evap. Brine Recirc. Piping	135,347
33	Surry GT-2 Computer	161,739
34	Possum Point 4 Generator Upper Stat. Winding	1,825,914
35	Possum Point CT 5 1st & 2nd Stage Buckets	121,207
36	Chesterfield #4 1st & 2nd Stage Turbine Blades	255,757
37	Bremo 3 Turbine Rotor/Generator	5,481,172
38	Chesterfield Power Station Replmt Unit 3 Pendant Assembles	394,637
39	Possum Point Power Station Forklift	101,773
40	Chesterfield #3 1st & 8th Stage Turbine Buckets	121,513
41	Chesterfield Power Station Coal Yard Locomotive	462,655
42	Possum Point Fuel Oil Heaters Skids	135,548
43		
44		
45		
46	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

CONSTRUCTION WORK IN PROGRESS—ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress—Electric (Account 107) (b)
	Virginia (Cont'd)	
1	Chesterfield Ash Pond Mod.	$ 132,319
2	Spent Fuel Storage Installation	1,641,762
3	Chesterfield Units 3&4 Purite System	226,287
4	Reactor Vessel Level Indication System - North Anna 1	2,996,734
5	Reactor Vessel Level Indication System - North Anna 2	2,811,067
6	Reactor Vessel Level Indication System	1,226,467
7	North Anna RX Vessel Vent TMI	2,408,407
8	North Anna #2 Reactor Head & Press Vent System	563,918
9	Surry RX Vessel Vent TMI	1,727,592
10	Surry #2 Reactor Head & Press Vent System	477,095
11	North Anna Early Warning Siren System	1,032,157
12	Surry Early Warning Siren System	933,381
13	Surry Subsurface Drain System	734,119
14	Surry Energy Bus Degrade Volt Protection	526,205
15	Surry Reserve St. Ser. Mod.	909,338
16	North Anna Waste Storage Building	809,612
17	Surry Power Station Meteorological Montrg. Upgrade	236,987
18	North Anna #1 Backup Overcurrent Protection Mod.	640,582
19	North Anna 2 Electrical Penetration	2,653,530
20	Surry 1&2 Heat Tracing System	3,627,581
21	Surry Radiation Monitor TMI	2,270,091
22	North Anna Meterological Monit-Tele System	328,811
23	Surry Post Accident Shield TMI	3,327,571
24	Surry Gas Turbine Fire Protection	326,354
25	Surry Cont. Accident Monitor TMI	4,062,146
26	Bremo Ash Disposal Master Plan Pond	882,429
27	Surry 1&2 Cont. & Recir. Spray RPL Valve	228,789
28	Surry Aux. Feedwater Flow Orifices	590,939
29	North Anna IE Equipment	2,597,266
30	North Anna #2 Reactor & Electrical Equipment	2,173,683
31	Surry Class IE Equipment	2,222,387
32	Surry #2 Reactor & Electrical Equipment	2,279,949
33	North Anna Nureg 06 96 Short Term I&C	4,754,347
34	Surry Nureg 06 96 Short Term I&C	4,406,892
35	Surry Control Room Habit	473,474
36	North Anna Power Station Poison Spent Fuel Rack	192,256
37	Possum Point Admin. Building	145,697
38	Possum Point - New Warehouse	495,182
39	System Maintenance Support Facility	2,028,148
40	North Anna Unit 1 Reactor Guide Tube Assembly	4,622,741
41	North Anna Unit 1 MSR Mod. & Tube Bundle Repl.	1,311,685
42	North Anna #1 Electric Generator	14,505,491
43	North Anna 1 Eddy Current Equipment	125,149
44		
45		
46	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 82

CONSTRUCTION WORK IN PROGRESS—ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress—Electric (Account 107) (b)
	Virginia (Cont'd)	
1	Possum Point 1st & 2nd Stage Buckets	$ 276,664
2	Portsmouth Power Station Unit 4 HP Turbine Blade	350,293
3	Portsmouth Power Station Rail Car Mover	467,325
4	Chesterfield #6 Air Preheater Upgrade	304,604
5	Chesterfield #5 Inst. & Cntl Modification	2,248,965
6	Chesterfield Power Station Unit 5 Turbine	1,421,471
7	Possum Point #3 Boiler Control Room	140,391
8	Surry Radiation Monitor	197,875
9	Surry Large Bore Snubber Mods.	725,982
10	Surry Main Steam Monorail Support Mods.	236,897
11	Surry I&C Vital Bus Mods.	340,353
12	North Anna Simulator/Training Center	10,732,029
13	North Anna 1&2 Steam Generator Inspection	1,107,133
14	North Anna Rotors	14,866,604
15	North Anna Diesel Generator Mod.	1,291,200
16	North Anna I.B. 79-27 Mod. Unit 1&2	740,519
17	Surry - Large Bore Snubber Mod. #2	885,052
18	Surry - Process Vent Mod.	138,102
19	Surry RWST Narrow Range Level Indication	144,207
20	North Anna 1 Rebuild B. LP Turbine Rotor	1,703,759
21	North Anna Service Water Upgrade	374,446
22	In-Service Inspection System North Anna & Surry 12-82	627,471
23	North Anna Rod Cluster Control Change Tool	110,466
24	Surry - Upgrade High & Low Level Intake Screen	179,216
25	North Anna Porv. and Safety Valve Mods.	235,355
26	North Anna #1&2 SG Blowdown Recovery	154,265
27	Surry Drawing Updates	1,192,031
28	Surry Emergency Communications System	157,309
29	Surry 1 & 2 R.G. 1.97 Mods.	137,533
30	Surry 1 & 2 Nureg - 0162 Mods.	783,041
31	Surry 1 & 2 Rep. Switchgear Cable-Low Level	195,542
32	Surry 1 & 2 5KV Replacement Electrical Pen.	520,714
33	Surry Charge Pump/SV UTR Pump Repl.	113,371
34	Surry - Loose Parts Monitoring System	374,594
35	Yorktown 2 Electro Precipitator	5,058,623
36	Chesterfield 6-Bal. Draft Com.	11,561,392
37	Chesterfield #5 Balanced Draft Conversion	12,819,898
38	North Anna - Onsite Technical Center	3,118,353
39	Surry 1&2 Onsite Center	3,678,611
40	Yorktown 1-2-3 Ash Disposal	2,562,642
41	Yorktown 1-2-3 Ash Disposal	2,257,638
42	Chesterfield #3 Electrostatic Precipitator	6,942,773
43		
44		
45		
46	TOTAL	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

CONSTRUCTION WORK IN PROGRESS—ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a) Virginia (Cont'd)	Construction Work in Progress—Electric (Account 107) (b)
1	Extension Circuit 311 to Mark Center Plaza II	$ 187,332
2	Falls Church Get-A-Way Improvement	101,873
3	Crystal Sub Get-A-Way Improvement	111,949
4	Substation Equipment Imp. & Repl. $100,000	127,874
5	WMATA K-Route	503,830
6	Second Pender 230-34.5KV Transformer	1,069,684
7	Hunter Sub	744,075
8	Conversion of Odricks Circuit 885	168,884
9	Sterling Park Section 2 Cable Repl.	127,287
10	Reston Substation Replace Transformer	695,253
11	Franconia 230-5KV Sub	643,077
12	Hayfield Sub 8th & 9th Circuit	350,293
13	Substation Equipment Imp. & Repl. $100,000	109,754
14	115-35KV Middleburg TRF and Reconductor	221,880
15	Substation Equipment Imp. & Repl. $100,000	115,915
16	Substation Equipment Imp. & Repl. $100,000	122,216
17	Stuarts Draft Sub - Inst. Add. Trfr. & Circuit	315,110
18	Substation Equipment Imp. & Repl. $100,000	151,083
19	Substation Equipment Imp. & Repl. $100,000	104,903
20	Substation Equipment Imp. & Repl. $100,000	129,633
21	Substation Equipment Imp. & Repl. $100,000	266,601
22	Van Dorn Sub Replace 230-34.5KV Trf. #2	368,800
23	Substation Equipment Imp. & Repl. $100,000	117,363
24	Substation Equipment Imp. & Repl. $100,000	103,171
25	Yorktown Add Water Storage Fire System	146,300
26	System Boiler Training Simulator	184,993
27	System Pollution Testing Van	151,630
28	Various Power Station Cpts Concepts for MPP	913,879
29	North Anna MIS Trending & Tracking System	170,827
30	Plant Imp. - Env. Ser. - $25,000 Limit	132,289
31	North Anna - Louisa 230KV Right-of-Way	104,507
32	Mt. Storm Microwave	145,942
33	Micro Comm. Exp-Sys. Cent - Southern Div.	798,295
34	Telephone System PBX Upgrade	147,027
35	Western Division Radio Improvement	249,461
36	Alleghany Dist. Hdg. Bldg.	412,149
37	Industrial Transformers & Equipment	2,444,000
38	Substation Equip., Imp. & Repl. - $100,000 Limit	2,824,719
39	TOU Metering-Plan Iw 2 Ripple Cont. WH	453,760
40	TOU Metering-Plan Iw 3-Radio Cont. WH	258,326
41	TOU Metering-Plan Iw 4-Auto Meter Reading	434,183
42	Division Supervisory Contro - Western	121,752
43	Substation Equipment Imp. & Repl. - $100,000	575,051
44		
45		
46	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

CONSTRUCTION WORK IN PROGRESS—ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a) Virginia (Cont'd)	Construction Work in Progress - Electric (Account 107) (b)
1	Chesterfield Unit 6 Primary & 2nd Water Airheater	$ 193,196
2	Chesterfield Warehouse Storage Addition Stock	150,860
3	Yorktown #3 Gas Pipeline	3,022,430
4	Portsmouth Unit 1 Coal Conversion Project	144,610
5	Possum Point Unit 3 Cooling Tower Drift Elim.	140,810
6	Yorktown Power Station Mobile Package Boiler	187,784
7	Bath County Pumped Storage - License 2716	763,049,622
8	Twelfth Street Hydroelectric Project	133,681
9	Bath-Valley 500KV Line & Right-of-Way	10,858,255
10	Bath-Lexington 500KV Line & Right-of-Way	12,233,691
11	Relocation Projects - Trans-Customer Exp.	854,052
12	Relocation Projects - Trans-Company Exp.	1,253,706
13	Remington-Warrenton 115KV Line & Sub	3,667,633
14	Ox-Possum Point-Pepco 500KV Line	752,481
15	North Anna-Possum Point-500KV Lines & Sub	4,006,365
16	Gordonsville Sub	510,624
17	Gordonsville - Charlottesville 230KV Reb.	873,424
18	Hollymeade 230KV Line & Sub	503,173
19	Avon-Clarendon 230KV UG Line & Subs	2,285,523
20	Drainsville 230KV Line & Sub	948,542
21	Tyson-CIA-Idylwood 230KV Line & Conv.	6,678,818
22	Fredericks-Arnolds Corner 115KV Uprate	315,470
23	Docms-Charlottesville 1st 230KV Conv.	1,948,325
24	Remington-Gordonsville 230KV Line	997,923
25	Lexington-Lowmoor 230KV Line	3,595,528
26	Septa-Fentress 500KV Line & Sub	1,099,392
27	Fentress-Reeves 230KV Line & Sub	284,193
28	Altavista-Klopman Mills Tap 115KV Rebuild	292,255
29	Elmont-Ladysmith Uprate 500KV Line	574,100
30	Altavista-Sub-Install 115KV Capacitor	133,907
31	Yadkin Sub-Install 2nd 500/230KV TX Bank	334,303
32	RF&P Relocation - Glebe - Jefferson Street	149,066
33	Emergency Spare Circuit Breakers	101,248
34	Braddock Annandale 230KV Lines & Sub	160,765
35	Rep. North Anna #2 Gen. Transformer	482,033
36	Burke - Ravensworth 115KV	753,722
37	North Anna - Gordonville 230KV Line	171,727
38	North Anna Unit 1 Cops	152,616
39	Transportation Equipment	115,920
40	Bath-Lexington-Richmond Microwave	615,953
41	Grayland Avenue - HVAC System	457,959
42	7th and Franklin Streets Electric Building Renovation	1,000,156
43	Electric Building Telephone System	560,824
44		
45		
46	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 82

CONSTRUCTION WORK IN PROGRESS—ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a) Virginia (Cont'd)	Construction Work in Progress – Electric (Account 107) (b)
1	Computer Aided Drafting T&D Const.	$ 198,411
2	OJRP-Computer-Aided Drafting & Design	513,936
3	OJRP Records Management Project - North Anna 3	417,098
4	Grayland Avenue - System T&D Operation Facilities	416,646
5	Communication Equipment - $25,000 Limit	147,918
6	Chesterfield - New District Headquarters	888,982
7	Central Div. Telephone System - Auto Call District	492,871
8	Central Div. Operation Center	155,337
9	Div. Operations Center - Eastern Division	143,373
10	UHF Radio System - Common Utility	184,997
11	Communication Equipment - $25,000 Limit	104,523
12	Herndon District Office Addition	353,351
13	Altavista - New Service Building	803,107
14	Communications Equipment - $25,000 Limit	100,341
15	M&S - High Rise Storage System	3,068,872
16	Div. Supervisory Control	257,994
17	Load Survey Magnetic Tap Recorder	278,231
18	Division Supervisory Control - Central	348,254
19	Remote Control WH-Eastern Div.	102,231
20	Repair of Hopewell #1 Transformer	297,089
21	Repair of Hopewell #2 Transformer	279,538
22	Thalia Sub #4 Tx. Rebuild	254,869
23	System Spare - 115-36.5KV 45MVA LTC Tx.	288,618
24	Hopewell Va. Continental Forest Ind. 20MVA	106,395
25	Substation Equipment IMP. & Repl. $100,000	368,813
26	Maidens Sub. Part Conversion	117,314
27	12th Street 5th & 6th 34.5KV Circulation	352,557
28	Lakeside Sub 6th 34.5KV Tx.	101,514
29	12th St. Sub. Inst. 13.2KV Cap Banks	118,386
30	Elmont Replace Tx.	344,533
31	Hopewell - 3rd 34.5KV Bus. Section	361,965
32	Falling Creek Sewage Treatment Plant Service	188,024
33	Northeast Sub Split Cir. 301	103,039
34	Turner Sub R/P 2-115-34.5KV Transfr.	437,472
35	Substation Equipment Imp. & Repl. $100,000	232,126
36	Green Run Sub 2nd Transf. & 4th Circuit	642,263
37	Va. Beach, Va. Thalia Substation 6th 34.5KV Circ.	177,425
38	Substation Equipment Imp. & Repl. $100,000	272,808
39	Substation Equipment Imp. & Repl. $100,000	142,302
40	Industrial Transformer & Equipment	106,398
41	Substation Equipment Imp. & Repl. $100,000	109,356
42	Suffolk Sub 115-34.5KV 20MVA	406,451
43	Glebe Sub 230-34.5KV Transformer	312,614
44		
45		
46	TOTAL	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

CONSTRUCTION WORK IN PROGRESS—ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).

2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).

3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress — Electric (Account 107) (b)
	Virginia (Cont'd)	
1	Wan Sub 2nd 115 34.5KV transformer	$ 138,125
2	Substation Equipment Imp. & Repl. - $100,000	164,563
3	Portsmouth NNSY 115-5KV 2-20MVA Tx	121,356
4	Possum Point #3 Electrostatic Precipitator	6,036,876
5	Other Minor Projects Less Than $100,000 Each	13,234,648
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7	Subtotal Virginia	1,112,751,781
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46	TOTAL	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

CONSTRUCTION WORK IN PROGRESS—ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project Virginia (Cont'd) (a)	Construction Work in Progress—Electric (Account 107) (b)
1		
2	Research and Development	
3	Bath County Pumped Storage Units	
4	Ecological Study	$ 19,400
5	Game Study	11,875
6	Biological - Chemical - Physical Studies	119,388
7	Permit Study	121,250
8	Trash Rack Design	382,159
9		654,072
10		
11	Chesterfield Power Station	
12	Coal Mill Upgrading Program	3,612
13		
14	North Anna Power Station	
15	Corrosion Probability - Service Water System	16,397
16		
17	System	
18	Stack Emissions Monitoring Studies	819
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21	Total Research and Development	674,900
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46	TOTAL Virginia	$ 1,113,426,681

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

CONSTRUCTION WORK IN PROGRESS—ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a) North Carolina	Construction Work in Progress – Electric (Account 107) (b)
1	Kitty Hawk GT-2 Computer	$ 136,857
2	Kitty Hawk GT-1 Computer	159,179
3	Fossil and Hydro Oper. Power Supply	139,719
4	Kitty Hawk to Whalebone 115KV Line & Sub	2,894,834
5	Consolidated Diesel Company Service	435,221
6	Micro Comm. Exp.-Sys. Central, Southern Division	299,623
7	Communication Equipment - $25,000 Limit	100,783
8	Southern Division Radio Improvement	110,224
9	Ahoskie Service Building	117,993
10	Transportation Equipment	193,310
11	TOU Metering-Remote Control - North Carolina	356,413
12	Substation Equipment Imp. & Repl. $100,000	220,403
13	N.C. Service To Polylok Anaconda Sub	222,361
14	Substation Equipment Imp. & Repl. $100,000 each	115,915
15	Kitty Hawk Sub Split 34.5KV Main Bus	169,295
16	Other Minor Projects Less Than $100,000 each	737,901
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22		
23	Total North Carolina	6,410,031
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46	TOTAL	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

CONSTRUCTION WORK IN PROGRESS—ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress—Electric (Account 107) (b)
	West Virginia	
1	Plant Improvement $25,000 Limit - Mt. Storm	$ 1,987,822
2	Mt. Storm Modify Pyrite System - Units 1-3	2,969,872
3	Mt. Storm - Unit 1 Ignitors	465,908
4	Mt. Storm - Spare BCP Motor	373,863
5	Mt. Storm Truck Sampling System	145,734
6	Mt. Storm Precipitator Hopper Level ID	232,738
7	Mt. Storm Dust Removal - New Crusher House	154,443
8	Mt. Storm 4KV Switchgear Spare Breaker	152,684
9	Mt. Storm #1&2 Turbine Supv. Instrument	358,105
10	Mt. Storm #3 BCP & Motor	122,206
11	Other Mt. Storm Comb. Turbine Relocation	130,106
12	Mt. Storm 2 Reheat Tubes	229,408
13	Mt. Storm #3 Precipitator Refurbishment	228,976
14	Mt. Storm #3 Computer RPL	551,521
15	Mt. Storm Roadway Improvement	717,657
16	Mt. Storm 1&2 RPL Voltage Regulator	252,421
17	Mt. Storm 110 Ton Locomotive	457,451
18	Mt. Storm #1 Air Preheater Cold Basket	208,222
19	Mt. Storm Covered Coal Conveyor Belt	261,930
20	Mt. Storm 1&2 SO2 Monitoring Sys. Comm.	171,431
21	Mt. Storm Coal Yard Improvement	379,563
22	Mt. Storm #2 Precipitator Heater Throat	217,577
23	Ports GT-7 1st Row Turbine Blades	144,261
24	Mt. Storm #1 Precipitator Preheater Throat	251,187
25	Mt. Storm #3 ESP Preheater Throat	129,829
26	Mt. Storm HDT & INT. Preheater	413,937
27	Mt. Storm Electrostatic Precipitators	964,166
28	Mt. Storm 1 Balance Draft Com.	33,458,475
29	Mt. Storm 2 Balance Draft Com.	19,276,785
30	Mt. Storm Precipitators VAC. Comm.	446,175
31	Mt. Storm Aux. Boiler	107,742
32	Hydrobin Piping Modification	784,712
33	Mt. Storm Power Station Elevator (Buck Hoist)	183,290
34	Mt. Storm Half-Round Claypipe	287,181
35	Mt. Storm Unit 3 Rotor BBC Shop	315,930
36	Various Power Station CPTS Concepts for MPP	138,862
37	Mt. Storm 1-2&3 Onsite Ash Disposal	1,164,046
38	Mt. Storm Sub Repl 396KV Arrestor	107,593
39	Mt. Storm Microwave	370,981
40	Other Minor Projects Less Than $100,000 each	1,882,097
41		
42	Subtotal - West Virginia	71,196,887
43		
44		
45		
46	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 82

CONSTRUCTION WORK IN PROGRESS—ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a) West Virginia (Cont'd)	Construction Work in Progress – Electric (Account 107) (b)
1	Research and Development	
2	Mount Storm Power Station	
3	Coal Mill Upgrading Program	$ 3,613
4		
5	Total West Virginia	71,200,500
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46	TOTAL	$ 1,191,037,212

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

CONSTRUCTION OVERHEADS—ELECTRIC

1. List in column (a) the kinds of overheads according to the titles used by the respondent. Charges for outside professional services for engineering fees and management or supervision fees capitalized should be shown as separate items.
2. On page 212 furnish information concerning construction overheads.
3. A respondent should not report "none" to this page if no overhead apportionments are made, but rather should explain on page 212 the accounting procedures employed and the amounts of engineering, supervision and administrative costs, etc., which are directly charged to construction.
4. Enter on this page engineering, supervision, administrative, and allowance for funds used during construction, etc., which are first assigned to a blanket work order and then prorated to construction jobs.

Line No.	Description of Overhead (a)	Total Amount Charged for the Year (b)
1	Construction Engineering	$ 21,780,164
2	Construction Supervision	22,317,886
3	General Office Salaries and Expenses Applicable to Construc-	
4	tion	10,892,665
5	Construction Engineering and Supervision By Others	50,652,005
6	Insurance, Injuries and Damages During Construction	952,286
7	Allowance For Funds Used During Construction	(91,121,387)
8	Company Automobile and Truck Transportation	2,064,410
9		
10		
11		
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45		
46	TOTAL	$ 17,538,029

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

GENERAL DESCRIPTION OF CONSTRUCTION OF OVERHEAD PROCEDURE

1. For each construction overhead explain: (a) the nature and extent of work, etc., the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.

2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Electric Plant Instructions 3 (17) of the U.S. of A.

3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

Refer to Page 212-A

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

For line 1(5), column (d) below, enter the rate granted in the last rate proceeding. If such is not available, use the average rate actually earned during the preceding three years.

1. Components of Formula (Derived from actual book balances and actual cost rates):

Line No.	Title (a)	(Thousands) Amount (b)	Capitalization Ratio (Percent) (c)	Cost Rate Percentage (d)
(1)	Average Short-Term Debt	S $ 82,293		
(2)	Short-Term Interest			s 12.25%
(3)	Long-Term Debt	D $2,923,893	52.67%	d 9.25%
(4)	Preferred Stock	P 675,284	12.16%	p 8.51%
(5)	Common Equity *	C 1,952,477	35.17%	c 15.00%
(6)	Total Capitalization	$5,551,654	100%	
(7)	Average Construction Work in Progress Balance	W $1,405,670		

2. Gross Rate for Borrowed Funds $s\left(\frac{S}{W}\right) + d\left(\frac{D}{D+P+C}\right)\left(1 - \frac{S}{W}\right)$

Gross				Net of Tax
5.32%	x	54%	=	2.87%

3. Rate for Other Funds $\left(1 - \frac{S}{W}\right)\left[p\left(\frac{P}{D+P+C}\right) + c\left(\frac{C}{D+P+C}\right)\right]$

5.87% 5.87%

8.74%**

4. Weighted Average Rate Actually Used for the Year:
   a. Rate for Borrowed Funds—
   b. Rate for Other Funds—

Gross				Net of Tax
5.21%	x	54%	=	2.81%
5.58%				5.58%
				8.39%***

* Includes Other Paid-In Capital at zero cost.
** Computed in accordance with FERC methodology.
*** Computed in accordance with Virginia State Corporation Commission (primary regulatory jurisdiction) methodology where certain cost-free capital was included in capitalization.

CONSTRUCTION OVERHEADS - ELECTRIC

Construction overheads applicable to construction were charged directly on the basis of actual time and expense into separate construction overhead accounts for each class of overhead. The accounts were used where applicable for each construction job and the overheads were distributed to each plant account affected on the basis of gross project charges at the completion of the job.

Construction engineering, included in direct construction cost, represents salaries and expenses of distribution engineers and their assistants on an actual time basis.

Construction supervision, included in direct construction cost, represents salaries and expenses of distribution superintendents, general foremen, and their assistants on an actual time basis.

Allowance for Funds Used During Construction (AFUDC) is calculated on a net of tax basis. During 1982 AFUDC was charged at a rate of 8.39% per annum.

For expenditures on the Bath County Pumped Storage Project after December 31, 1979, AFUDC is being accrued in an amount equal to the net of tax cost of borrowings associated with the Project Financing, up to a limit of $250,000,000.

In August 1981, the Virginia Commission issued an order that included the Company's proposal to eliminate AFUDC on additional construction expenditures for North Anna Unit No.3 and on all new projects commencing after September 1, 1981.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company System	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, line 11, column (c), and that reported for electric plant in service, pages 202-204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	$1,256,857,188	$1,256,857,188		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	184,368,000	184,368,000		
4	(413) Expenses of Electric Plant Leased to Others				
5	Transportation Expenses–Clearing	3,445,000	3,445,000		
6	Other Clearing Accounts				
7	Other Accounts *(Specify)*				
8					
9	TOTAL Depreciation Provisions for Year *(Enter Total of lines 3 thru 8)*	187,813,000	187,813,000		
10	Net Charges for Plant Retired				
11	Book Cost of Plant Retired	36,407,506	36,407,506		
12	Cost of Removal	12,292,545	12,292,545		
13	Salvage (Credit)	19,159,281	19,159,281		
14	TOTAL Net Charges for Plant Retired *(Enter Total of lines 11 thru 13)*	29,540,770	29,540,770		
15	Other Debit or Credit Items *(Describe)* Accumulated Provision To Net	(4,547,514)	(4,547,514)		
16	Transfers of Property & Adjustment To Salvage				
17	Balance End of Year *(Enter Total of lines 1, 9, 14, 15, and 16)*	1,410,581,904	1,410,581,904		

Section B. Balances at End of Year According to Functional Classifications

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
18	Steam Production	448,131,620	448,131,620		
19	Nuclear Production	297,476,134	297,476,134		
20	Hydraulic Production–Conventional	26,406,347	26,406,347		
21	Hydraulic Production–Pumped Storage				
22	Other Production	810,514	810,514		
23	Transmission	174,977,223	174,977,223		
24	Distribution	427,921,607	427,921,607		
25	General	34,858,459	34,858,459		
26	TOTAL *(Enter Total of lines 18 thru 25)*	1,410,581,904	1,410,581,904		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

NONUTILITY PROPERTY (Account 121)

1. Give a brief description and state the location of nonutility property included in Account 121.
2. Designate with an asterisk any property which is leased to another company. State name of lessee and whether lessee is an associated company.
3. Furnish particulars (details) concerning sales, purchases, or transfers of Nonutility Property during the year.
4. List separately all property previously devoted to public service and give date of transfer to Account 121, *Nonutility Property*.
5. Minor items (5% of the Balance at the End of the Year for Account 121 or $100,000, whichever is less) may be grouped by (1) previously devoted to public service (line 43), or (2) other nonutility property (line 44).

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Purchases, Sales, Transfers, etc (c)	Balance at End of Year (d)
1-4	Property Having a Book Value of $100,000 or More or Previously Devoted to Public Service	$	$ See details on Pages 215-C and 215-D	$
6-8	Manchester hydro land and riparian rights on James River, Richmond, Virginia 1965	156,253		156,253
9-13	Parcel of land on west side of North 8th Street between East Grace and East Franklin Streets in Richmond, Virginia 1970	214,153		214,153
14-16	Former Beauregard Substation site, Fairfax County, Virginia 1977	171,912		171,912
17-19	Former Landtowne Substation site, Virginia Beach, Virginia 1977	110,505		110,505
20-23	(A) Former System Office Land - 7th and Franklin Streets, Richmond, Virginia 1979	146,301		146,301
24-27	Chesterfield Power Station Wheelwright Property, Chesterfield County, Virginia 1976	177,980		177,980
28-30	Former Elmont 500KV Line Easements 1976	575,895		575,895
31-33	Former Burke, - Ravensworth 115KV Line Easements 1978	471,644		471,644
34-36	Former Reeves Avenue Power Station property, Norfolk, Virginia 1976	3,732,499		3,732,499
37-39	Former North Anna - Louisa 230KV Line Easements 1978	111,603		111,603
40-42	Mount Storm Baird-Gatzmer Tract, Grant County, West Virginia 1980	316,264		316,264
43	Minor Item Previously Devoted to Public Service			
44	Minor Items — Other Nonutility Property			
45	TOTAL			

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

NONUTILITY PROPERTY (Account 121)

1. Give a brief description and state the location of nonutility property included in Account 121.
2. Designate with an asterisk any property which is leased to another company. State name of lessee and whether lessee is an associated company.
3. Furnish particulars (details) concerning sales, purchases, or transfers of Nonutility Property during the year.
4. List separately all property previously devoted to public service and give date of transfer to Account 121, *Nonutility Property*.
5. Minor items (5% of the Balance at the End of the Year for Account 121 or $100,000, whichever is less) may be grouped by (1) previously devoted to public service (line 43), or (2) other nonutility property (line 44).

Line No.	Description and Location (a)		Balance at Beginning of Year (b)	Purchases, Sales, Transfers, etc (c)	Balance at End of Year (d)
1–3	Former Pig Point Power Station site Suffolk, Virginia	1976	$ 469,874	$	$ 469,874
4–6	Former Twelfth Street Power Station property, Richmond, Virginia	1976	1,670,480	(381,527)	1,288,953
7–9	Power Station site, Stafford County, Virginia	1975	308,425		308,425
10–12	Clifton Substation site, Fairfax County, Virginia	1982		164,184	164,184
13–16	Ox-Occoquan-Pohick-Van Dorn Right-of-Way property, Prince William County, Virginia	1982		345,727	345,727
17–20	(A) Former System Office Building, 7th and Franklin Streets, Richmond, Virginia	1979	3,076,984		3,076,984
21–23	Land adjacent to Yorktown Power Station, York County, Virginia	1976	175,600		175,600
24–26	Former Twelfth Street Power Station site, Richmond, Virginia	1976	144,083	(144,083)	
27–29	Fredericksburg District Office Building, Fredericksburg, Virginia	1980	221,511	(221,511)	
30			12,251,966	(237,210)	12,014,756
31	Minor Items		109,999	(23,647)	86,352
32–35	Total of property having a book value of $100,000 or more or previously devoted to public service		12,361,965	(260,857)	12,101,108
36					
37					
38					
39					
40					
41					
42					
43	Minor Item Previously Devoted to Public Service				
44	Minor Items – Other Nonutility Property				
45	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

NONUTILITY PROPERTY (Account 121)

1. Give a brief description and state the location of nonutility property included in Account 121.
2. Designate with an asterisk any property which is leased to another company. State name of lessee and whether lessee is an associated company.
3. Furnish particulars (details) concerning sales, purchases, or transfers of Nonutility Property during the year.
4. List separately all property previously devoted to public service and give date of transfer to Account 121, *Nonutility Property.*
5. Minor items (5% of the Balance at the End of the Year for Account 121 or $100,000, whichever is less) may be grouped by (1) previously devoted to public service (line 43), or (2) other nonutility property (line 44).

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Purchases, Sales, Transfers, etc (c)	Balance at End of Year (d)
1				
2	Property Having a Book Value of Less than			
3	$100,000 and Not Previously Devoted to			
4	Public Service			
5				
6	Virginia	$ 595,848	$ (12,539)	$ 583,309
7	Maryland	56,640		56,640
8	West Virginia	7,928		7,928
9	North Carolina	107,108	76,461	183,569
10	Total not previously devoted to public			
11	service	767,524	63,922	831,446
12				
13				
14				
15				
16				
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39				
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41				
42				
43	Minor Item Previously Devoted to Public Service			
44	Minor Items – Other Nonutility Property			
45	TOTAL	$13,129,489	$ (196,935)	$12,932,554

NONUTILITY PROPERTY ACCOUNT (121 CONT'D)
SALE, TRANSFER OR OTHER DISPOSITION 1982

Additions to Nonutility Property by Transfer	Accounts Debited or Credited	Book Value	Expense of Sale	Proceeds
Clifton Substation Site - Fairfax County, Virginia	105.0	$164,184		
Ox-Occuquan-Pohick-Van Dorn Right-of-Way Property-Prince William County, Virginia	105.0	345,727		
Winfall Substation Site - Perquimans County, North Carolina	105.0	77,790		
Total Additions		$587,701		

NONUTILITY PROPERTY ACCOUNT (121 CONT'D)
SALE, TRANSFER OR OTHER DISPOSITION 1982

Retirements to Nonutility Property by Transfer or Sale	Accounts Debited or Credited	Book Value	Expense of Sale	Proceeds
Former Virginia Beach Gas Corp. Building, Virginia Beach, Virginia	421.2	$ 1,181	$	$
Sale of Former Fredericksburg District Office Building and Land Fredericksburg, Virginia	143.1	245,158	200	199,800
Sale of Roanoke Rapids Power Station Land, Roanoke Rapids, North Carolina	143.1	1,329		3,000
Sale of Laurel Hill Hydro Station Land, Augusta County, Virginia	143.1	500		3,202
Reversion of Balcony Falls Hydro Land, Rockbridge County, Virginia	421.2	10,858		
Transfer of 12th Street Environmental Lab, Richmond, Virginia	101.0	525,610		
Total Retirements		$784,636		
Total Decrease 1982		$196,935		

NONUTILITY PROPERTY PREVIOUSLY DEVOTED TO PUBLIC SERVICE

Virginia

Former Eanes Lane Substation Site - Henrico County	1956
Former Yorktown Substation Site - Ferris Tract	1956
Terminal Avenue Regulator Station - Portion of Gas Plant Site - Newport News	1975
Clifton Forge Vacant Lot - Clifton Forge	1967
Newport News Gas Plant Land	1966
Former Reeves Avenue Power Station Site - Norfolk	1976
Reeves Avenue Power Station Structure - Norfolk	1976
Former Twelfth Street Power Station Site - Richmond	1976
Twelfth Street Power Station Structure - Richmond	1976
Penniman Tap Naval Fuel Oil Station Easement - 110KV - York County	1978
Building 7th & Franklin Streets - Richmond	1979
Restaurant Equipment - 7th & Franklin Building - Richmond	1979
Former System Office Land 7th & Franklin Streets - Richmond	1979
Transmission Easements - Prince William County	1951
Chesterfield Power Station Wheelwright Property - Chesterfield County	1976
Land and Land Rights in Fredericksburg, Virginia, formerly the location of the Fredericksburg Distribution Building Site	1980
Building located in Fredericksburg, Virginia, formerly the location of the Fredericksburg Distribution office	1980

West Virginia

Former Pence Springs Substation Site - Summers County	1950

(A) Portion of property leased to the City of Richmond which is not an associated company.

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 82

INVESTMENT IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, *Investment in Subsidiary Companies.*

2. Provide a subheading for each company and list thereunder the information called for below. Sub-total by company and give a total in columns (e), (f), (g) and (h).

(a) Investment in Securities — List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate.

(b) Investment Advances — Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.

3. Report separately the equity in undistributed subsidiary earnings since acquisition. The total in column (e) should equal the amount entered for Account 418.1.

4. For any securities, notes, or accounts that were pledged, designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.

5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.

6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.

7. In column (h), report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).

8. Report on line 23, column (a) the total cost of Account 123.1.

Line No	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings for Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1	Account 123.1							
2	Laurel Run Mining Company (a)							
3	Investment in Securities (b)	Various		$ 3,500,000			$ 3,500,000	
4	Investment in Advances (c)	Various		14,752,429			12,122,708	
5	Investment in Undistributed							
6	Earnings (d)	Various		2,815,536	$ 2,604,152		5,419,688	
7								
8	Virginia Nuclear (e)							
9	Investment in Securities (f)	Various		208,346			208,346	
10	Investment in Advances (g)	Various		5,437			5,732	
11								
12								
13								
14								
15								
16	See page 217-A for notes.							
17								
18								
19								
20								
21								
22								
23	Total Cost of Account 123.1: $ ______		TOTAL	$21,281,748	$ 2,604,152		$21,256,474	

INVESTMENT IN SUBSIDIARY COMPANIES
(ACCOUNTS 123.1)
NOTES TO PAGE 217

(a) Investment procedures approved by State Corporation Commission of Virginia 08/1[illegible]/72, Case No. 210; North Carolina Utilities Commission 09/06/72, Docket No. E-22, Sub 143; and West Virginia Public Service Commission 10/0[illegible]/72, Case No. 7540.

(b) Common stock, no par, 3,500,000 shares

(c) Open account

(d) One of the Company's two portals went into commercial operation January 1, 1979, Investment procedures were approved by the State Corporation Commission of Virginia 08/25/78, Case No. A-201. The Commission has approved inclusion in the price of coal an overall rate of return on total investment resulting from the application of the overall rate of return last approved by the Commission. Effective 08/29/81 rate of return was 10.68% (.89% per month); effective 05/01/82 rate of return increased to 10.88% (.907% per month).

(e) Investment procedures approved by State Corporation Commission of Virginia 11/17/75, Case No. A-446; West Virginia Public Service Commission 11/25/75, Case No. 8413; approval not required by North Carolina Utilities Commission.

(f) Common stock, no par, 31 shares

(g) Open account

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.

2. Give an explanation of important inventory adjustments during year (on a supplemental page) showing general classes of material and supplies and the various accounts (operating expense, clearing accounts, plant, etc.) affected—debited or credited. Show separately debits or credits to stores expense-clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (Dollars) (b)	Balance End of Year (c)	Department or Departments Which Use Material (d)
1	Fuel Stock (Account 151)	129,557,166	125,280,523	Elec. & Gas
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to – Construction (Estimated)	3,860,851	4,094,813	Electric
6	Assigned to – Operations and Maintenance			
7	Production Plant (Estimated)	49,067,647	113,239,437*	Electric
8	Transmission Plant (Estimated)	3,225,482	4,477,544	Electric
9	Distribution Plant (Estimated)	20,474,651	18,781,332	Electric
10	Assigned to – Other	372,566	482,633	Gas
11	TOTAL Account 154 *(Enter Total of lines 5 thru 10)*	77,001,197	141,075,759	
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)			
15	Stores Expense Undistributed (Account 163)	(77,427)	283,456	
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	206,480,936	266,639,738	

*Includes $46,915,718 transferred from Account 107 Electric Construction Work in Progress to Account 154 Plant Materials and Operating Supplies due to the cancellation of North Anna Unit No. 3.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 82

EXTRAORDINARY PROPERTY LOSSES (ACCOUNT 182)

Line No.	Description of Property Abandoned or Extraordinary Loss Suffered (Include in the description the date of abandonment or loss, the date of Commission authorization to use Account 182, and period of amortization (mo, yr to mo, yr).) (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR: Account Charged (d)	WRITTEN OFF DURING YEAR: Amount (e)	Balance at End of Year (f)
1	Surry Unit 3 (b)	(a)	$ 186,523	407	$ 6,611,987	$ 33,810,752
2	Surry Unit 4 (b)	(a)	(10,328)	407	2,743,647	17,762,101
3	Surry Unit 3 Fuel (c)	(a)	-	407	379,560	2,824,496
4	Surry Unit 4 Fuel (c)	(a)	-	407	190,584	1,248,059
5	North Anna Unit 4 (d)	(a)	334,053	407	11,001,497	113,732,860
6	North Anna Unit 4 Fuel (d)	(a)	-	407	293,373	3,022,906
7	North Anna Unit 3 (e)	(a)	453,811,212			453,811,212
8	North Anna Unit 3 Fuel (e)	(a)	2,206,511			2,206,511
9						
10			$456,527,971		$21,220,648	$628,418,897
11	.					
12						
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23						
24	(a) Refer to Note C to Financial Statements in the Company's 1982 Annual Report to Stockholders, attached, which					
25	notes are incorporated herein by reference.					
26	(b) Use of Account 182, approved by the State Corporation Commission of Virginia on 08/15/77, the North Carolina					
27	Utilities Commission on 11/20/77 and the FERC on 12/30/77					
28	(c) Use of Account 182, approved by the Commissions shown in Note (b) above, on 02/08/79, 11/10/77 and 04/30/79,					
29	respectively.					
30	(d) Use of Account 182, approved by the State Corporation Commission of Virginia on 08/29/81 and the North					
31	Carolina Utilities Commission on 10/27/81.					
32						
33	(e) Use of Account 182, approved by the State Corporation Commission of Virginia on 12/22/82.					
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46						
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48						
49						
50						
51	TOTAL					

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

MISCELLANEOUS DEFERRED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a).
3. Minor items (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debit (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1						
2						
3						
4	See Pages 223 - A and B.					
5						
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47	Misc. Work in Progress					
48	DEFERRED REGULATORY COMMISSION EXPENSES (See pages 350-351)					
49	TOTAL					

MISCELLANEOUS DEFERRED DEBITS (ACCOUNT 186)

Description of Miscellaneous Deferred Debits (a)	Balance Beginning of Year (b)	Debits (c)	Credits: Account Charged (d)	Credits: Amount (e)	Balance End of Year (f)
Reactor Loose Parts - Reactor Repairs N.A. 1	$ -0-	$ 515,907	Various	$ 347,978	$ 167,929
Reactor Loose Parts - Stm. Gen. Repairs N.A. 1	-0-	1,741,525	530.2	1,329,580	411,945
Reactor Loose Parts - Reactor Repairs Eng. N.A. 1	-0-	1,114,446	Various	645,030	469,416
Yorktown 3 Implosion Settlement	-0-	5,429,149*	426.5	1,633,705	3,795,444
N.A. 2 Reactor Thermal Sleeves	-0-	1,052,556			1,052,556
Def. Fuel Adj. FERC (VA - RC) - Current Period	-0-	4,179,465	557	1,533,449	2,646,016
Def. Fuel Adj. FERC (VA - RS) - Current Period	-0-	746,050	557	220,291	525,759
Def. Fuel Adj. FERC (NC - RC) - Current Period	-0-	1,064,866	557	659,821	405,045
Def. Fuel Adj. FERC (NC - RS) - Current Period	-0-	84,710	557	27,547	57,163
Def. Fuel Adj. FERC (NC - EMPA) - Current Period	-0-	1,076,779	557	426,897	649,882
Def. Fuel Adj. FERC (VA - RC) - Out-of-Period	-0-	2,254,696	557	1,925,333	329,363
Def. Fuel Adj. FERC (VA - RS) - Out-of-Period	-0-	359,611	557	248,949	110,662
Def. Fuel Adj. FERC (NC - EMPA) - Out-of-Period	-0-	699,714	557	635,813	63,901
Capacity Fuel Deferral	-0-	20,208,782	557	51,225	20,157,557
M.S. Def. Fuel Exp. - Out-of-Period	-0-	40,659	557	1,180,278	(1,139,619)
M.S. Def. Fuel Exp. - Current Period	-0-	1,656,905	557	519,140	1,137,765
Common Stock Offering	-0-	124,650			124,650
Louisa County Litigation	-0-	144,318			144,318
Ind. Dev. Poll. Control Rev. Bonds-Series of 1982	-0-	34,479,259	143.[illegible]	25,667,211	8,812,048
Comm. of Va. Misc. Sus. 1981 Def P&I Cap.	-0-	1,100,107	557	323,709	776,398
Comm. of Va. Misc. Sus. 1982 Def P&I Cap.- 7/82-3/83	-0-	604,727			604,727
Comm. of Va. Misc. Sus. 1982 Def P&I Cap.- 7/82-6/82	-0-	528,054			528,054
Three Yr. Poll. Control Note: Proj. Fund	-0-	5,090,552			5,090,552
AFUDC on North Anna Spare Parts & Equipment	-0-	21,154,668	Various	209,186	20,945,482
Corporate Reorganization	-0-	302,724			302,724
Laurel Run Fuel Def. - VA - Out-of-Period	-0-	447,577	557	1,236,511	(788,934)
Laurel Run Fuel Def. - VA - Current Period	-0-		557	2,120,896	(2,120,896)
$15M Poll Control Bond - Construction Fund	-0-	8,246,601			8,246,601
Laurel Run Memo Acct. Def. Fuel	-0-		557	64,058	(64,058)
Transfer Charges for Closing Purposes	-0-	2,796,784	Various	2,638,007	158,777
General Accounting J.E. Corrections	-0-	8,692,997	Various	8,316,334	376,663
Partial Sale of Facilities at N.A. to Co-ops	-0-	267,060	Various	1,573	265,487
Misc. Susp. Alt. Energy Study - Coal, Nuclear & Gas	-0-	75,272			75,272
Low Head Hydro	-0-	52,729			52,729
Non-conventional Fuels	-0-	131,202			131,202
Heat Pump Efficiency	-0-	59,788			59,788
Co-generation	-0-	67,222			67,222
Fuel Cells	-0-	65,306			65,306
Wind Turbines	-0-	75,567			75,567
Solar Electric	-0-	62,379			62,379
Misc. Studies	-0-	396,838			396,838
Customer Stock Purchase Plan	-0-	237,776	181.0	131,365	106,411
Deferred Fuel Adj. - Elec.	-0-	39,801,354	557	23,106,532	16,694,822
82-83 VA - Non-jurisdictional Fuel Def. Dr.	-0-	1,268,815	557	435,451	833,364
N.A. 1 Refueling Outage - 1982	-0-	1,804,584	Various	1,018,910	785,674
Spent Nuclear Fuel Ship Cask Lease Charges	-0-	63,148			63,148
M/S Nuclear Fuel Levelizing - SN-2	281,354	6,222,545	Various	6,503,899	-0-
Va. Non-jurisdictional Fuel Deferral - Cr.	(812,036)	2,028,666	557	1,216,630	-0-
Va. Non-jurisdictional Fuel Exp. Dr.	812,036	1,254,825	557	1,267,739	799,122
Headwater Benefits - Licensed Project 2009	70,965	89,796	184	38,907	121,854
Progress Payments - Batch 4 - Surry 1	2,809,414	52,042,149	Various	43,832,679	11,018,884
Progress Payments - Batch 4 - Surry 2	19,994,074	48,069,825	Various	29,035,651	39,028,248
Deferred P & I Capacity Charges - 1980	26,467,938	77,014	557	26,544,952	-0-
Deferred P & I Capacity Charges - 1981	42,386,979	6,354,537	557	22,187,866	26,553,650
Deferred P & I Capacity Charges - 1982	(78,777)	21,266,269			21,187,492
Deferred Fuel Adjustment - Electric	38,590,167		557	38,590,167	-0-
Deferred Gas Expenses - Automatic Cost Adjustment	1,071,155	1,609,314	728,804	1,056,316	1,624,153
Deferred Fuel Adjustment - Electric - Va. 04/81-04/82	29,344,778	55,075,995	557	51,039,981	33,380,792
Deferred Purchased Gas Adjustment	(782,276)	34,352,807	728,864	35,305,459	(1,734,928)
Payroll Charges Pending Reclassification	(21,914)	1,380,363	Various	1,313,964	45,485

*Represents Yorktown No. 3 capitalized implosion costs transferred from FERC Account 101, Electric Plant in Service to FERC Account 186. These costs, less the related accumulated depreciation, are being amortized over the remaining life of the unit.

MISCELLANEOUS DEFERRED DEBITS (ACCOUNT 186)

Description of Miscellaneous Deferred Debits (a)	Balance Beginning of Year (b)	Debits (c)	Credits: Account Charged (d)	Credits: Amount (e)	Balance End of Year (f)
Louisa Pollution Control Bond Fund Series B	$ 650,731	$ 30,735	237.1	$ 681,466	$ -0-
Maximum vs. variable prime - Hartford National Bank	1,143,947	359,465			1,503,412
Maximum vs. variable prime - Credit Suisse	962,784	303,961			1,266,745
Removal of Ga. Power Transformer and Replacement	(3,520)	4,120	Various	600	-0-
Maximum vs. variable prime - Provident National Bank	1,459,375	417,828			1,877,203
Maximum vs. variable prime - Girard Bank	4,374,604	1,250,895			5,625,499
Maximum vs. variable prime - the Chase Manhattan Bank, N.A.	14,799,260	4,258,529	431.0	3,093	19,054,696
Executive Supplemental Retirement Plan - Ins. Rec.	508,416	257,201			765,617
Bremo Ash Pond Expansion	18,645	1,447	Various	20,092	-0-
North Anna Service Water System Upgrade	15,130	2,101	Various	17,231	-0-
Post Accident Monitoring	12,370	233,349	Various	34,228	211,491
Mobilization and Support - NACIP Project	1,303,388	2,431,616	Various	3,684,108	50,896
PSE&C Special Projects - CCC 70	3,907	15,078	184	18,985	-0-
PSE&C Special Projects - CCC 71	2,598	8,713	Various	11,311	-0-
PSE&C Special Projects - CCC 72	14,580	19,110	Various	33,690	-0-
PSE&C Special Projects - CCC 73	2,876	5,299	Various	8,175	-0-
Chesterfield $25 Million Note Project Fund	25,000,000	2,188,827	143.1	27,188,827	-0-
Chesterfield $40 Million Note Project Fund	12,015,930	40,162,406	Various	52,178,336	-0-
Employee Stock Ownership	61,284	54,929	Various	166,213	-0-
Allied Chemical Nuclear Materials - Advance Payments	750,483	662,689	Various	750,483	662,689
1982 Common Stock Financing	768	168,135	214.0	168,903	-0-
Financing Expense $25 Million Chesterfield I.D.A.	5,000	105,083	Various	110,083	-0-
Miscellaneous Work in Progress	13,137,907				11,676,296
64 Minor Items Less Than $50,000	(58,440)	5,753,198	Various	5,000,628	699,953
Total	$236,314,880				$269,261,299

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Elec. & Power Co.	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 82

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other *(Specify)*, include deferrals relating to other income and deductions.
3. If more space is needed, use separate pages as required.

Line No.	Account Subdivisions *(a)*	Balance at Beginning of Year *(b)*	Balance at End of Year *(c)*
1	Electric		
2	Leaseback of Buildings (a)	$ 898,716	$ 829,584
3	Sale and Leaseback of Land for Construction of		
4	new general office building (b)	430,361	414,197
5	Yorktown Implosion Costs	-0-	69,007
6	Gains from Sale of Property-Greensville Facilities	-0-	1,314,779
7	Other		
8	TOTAL Electric *(Enter Total of lines 2 thru 7)*	$ 1,329,077	$ 2,627,567
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas *(Enter Total of lines 10 thru 15)*		
17	Other *(Specify)*		
18	TOTAL (Account 190) *(Enter Total of lines 8, 16 and 17)*	$ 1,329,077	$ 2,627,567

NOTES

In the space provided below, identify by amount and classification, significant items for which deferred taxes are being provided. Indicate insignificant amounts under Other.

(a) The deferral of the Federal income taxes attributable to the gain on the sale and leaseback of the West Broad Street, Herndon, and Virginia Beach service buildings is being amortized over twenty (20) years, commencing in 1975. Account 190 is not split between electric and gas. However, the monthly amortization (Account 410.1) is split between electric and gas based on floor space studies. During 1982, the amortization for electric was $67,368 and for gas was $1,764.

(b) The deferral of the Federal income taxes attributable to the gain on the sale and leaseback of the James River Plaza landsite is being amortized over the terms of the lease (30 years) commencing in mid-August 1978. Account 190 is not split between electric and gas. However, the monthly amortization (Account 410.1) is split between electric and gas based on the system ratio. During 1981, the amortization for electric was $15,684 and for gas was $480.

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec 31, 19 82

CAPITAL STOCK (Accounts 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to the report form (i.e. year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.

2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.

4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.

5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.

6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No	Class and Series of Stock and Name of Stock Exchange (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value Per Share (c)	Call Price at End of Year (d)	OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Amount (f)	HELD BY RESPONDENT: AS REACQUIRED STOCK (Account 217) Shares (g)	Cost (h)	IN SINKING AND OTHER FUNDS Shares (i)	Amount (j)
1	Account 201		$	$		$		$		$
2	Common Stock	150,000,000	NO PAR		119,517,685	1,6[illegible],71[illegible],066(a)		NONE		NONE
3										
4	Account 204									
5	Preferred Stock,									
6	Cumulative	7,500,000	$100							
7	$5.00 Dividend			112.50	106,677	10,667,700(b)		NONE		NONE
8	$4.04 Dividend			102.27	12,926	1,292,600		NONE		NONE
9	$4.20 Dividend			102.50	14,797	1,479,700		NONE		NONE
10	$4.12 Dividend			103.73	32,534	3,253,400		NONE		NONE
11	$4.80 Dividend			101.00	73,206	7,320,6[illegible]		NONE		NONE
12	$7.72 Dividend			103.50	350,000	35,000,000		NONE		NONE
13	$8.84 Dividend			104.00	350,000	35,000,000		NONE		NONE
14	$7.45 Dividend			103.00	400,000	40,000,000		NONE		NONE
15	$7.20 Dividend			103.00	450,000	45,000,000		NONE		NONE
16	$7.72 Dividend (1972 Series)			103.00	500,000	50,000,000		NONE		NONE
17	$7.325 Dividend			110.00	700,000	70,000,000		NONE		NONE
18	$8.40 Dividend			115.00	800,000	80,000,000		NONE		NONE
19	$9.75 Dividend			106.50	600,000	60,000,000		NONE		NONE
20	$9.125 Dividend			107.00	184,000	18,400,000		NONE		NONE
21	$8.20 Dividend			115.00	600,000	60,000,000		NONE		NONE
22	$8.60 Dividend			107.00	335,270	33,527,000		NONE		NONE
23	$8.625 Dividend			108.63	370,000	37,000,000		NONE		NONE
24	$8.925 Dividend			108.93	280,000	28,000,000		NONE		NONE
25										
26	Preference Stock, Cumulative					$ 615,941,000				
27	$2.90 Dividend	30,000,000	NO PAR	26.93	2,400,000	$ 57,360,000		NONE		NONE

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric & Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

CAPITAL STOCK (Accounts 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to the report form (i.e. year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Exchange (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value Per Share (c)	Call Price at End of Year (d)	OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent.) Shares (e)	Amount (f)	HELD BY RESPONDENT: AS REACQUIRED STOCK (Account 217) Shares (g)	Cost (h)	IN SINKING AND OTHER FUNDS Shares (i)	Amount (j)
1	FOOTNOTES:									
2										
3	*Total amount outstanding without reduction for amount held by respondent.									
4	(a) In addition, 2,380,476 shares are reserved for conversion (based on the conversion price of $21.00 per share)									
5	of the 3 5/8% Convertible Debentures, due May 1, 1986.									
6	(b) Excludes 19 shares reserved for exchange of outstanding script of prior issue not yet presented for exchange.									
7	(c) For additional information, see Notes H and I on pages 29 and 30 of the 1982 Annual Report to Stockholders,									
8	attached, which notes are incorporated herein by reference.									
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric & Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

CAPITAL STOCK SUBSCRIBED, CAPITAL STOCK LIABILITY FOR CONVERSION, PREMIUM ON CAPITAL STOCK, AND INSTALLMENTS RECEIVED ON CAPITAL STOCK (Accounts 202 and 205, 203 and 206, 207, 212)

1. Show for each of the above accounts the amounts applying to each class and series of capital stock.
2. For Account 202, *Common Stock Subscribed*, and Account 205, *Preferred Stock Subscribed*, show the subscription price and the balance due on each class at the end of year.
3. Describe in a footnote the agreement and transactions under which a conversion liability existed under Account 203, *Common Stock Liability for Conversion*, or Account 206, *Preferred Stock Liability for Conversion* at the end of the year.
4. For Premium on Account 207, *Capital Stock*, designate with an asterisk any amounts representing the excess of consideration received over stated values of stocks without par value.

Line No.	Name of Account and Description of Item (a)	Number of Shares (b)	Amount (c)
1	Installments Received on Capital Stock (Account 212)		$3,114,490
3	A Customer Stock Purchase Plan provides retail nongovernmental customers of the Company with a method of purchasing through 12 monthly installments shares of the Company's Common Stock without payment of any brokerage commission. The Plan is being administered by United Virginia Bank as agent.		
11	Interest accrues on the installment payments from the date of receipt by the bank at the rate of [illegible]%. The installment payments, plus accrued interest ([illegible]%) and less net expenses, are used to purchase shares of the Company's Common Stock.		
17	The Company pays for expenses associated with the Plan up to an amount equal to 4% of the aggregate amount of the subscriptions received. The net expenses (total expenses as reduced by such payment by the Company and forfeited interest) are borne proportionately by the participants in the Plan and reduce the aggregate amount used to purchase Common Stock.		
25	The purchase price of the shares is the average of the high and low sale prices for the Common Stock on the 20th day of each month during the 12-month period.		
46	TOTAL		$3,114,490

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) *Donations Received from Stockholders* (Account 208)—State amount and give brief explanation of the origin and purpose of each donation.

(b) *Reduction in Par or Stated Value of Capital Stock* (Account 209)—State amount and give brief explanation of the capital changes which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) *Gain on Resale or Cancellation of Reacquired Capital Stock* (Account 210)—Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) *Miscellaneous Paid-In Capital* (Account 211)—Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1		
2		
3		
4	Gain on Resale or Cancellation of Reacquired Capital Stock	
5	(Account 210)	
6		
7		
8		
9		
10		
11		
12	Balance at beginning of year	$24,515,995
13	Less: Transfer to common stock account	835,772
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40	TOTAL Balance at End of Year	$23,680,223

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

DISCOUNT ON CAPITAL STOCK (Account 213)

1. Report the balance at end of year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off during the year and specify the amount charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4	None	
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21	TOTAL	

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of year of capital stock expenses for each class and series of capital stock.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4	See notes to Statement of Retained Earnings on page 122.	
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22	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec 31, 19 82

LONG TERM DEBT (Accounts 221, 222, 223, and 224)

1. Report by balance sheet the account particulars (details) concerning long-term debt included in Accounts 221, *Bonds*, 222, *Reacquired Bonds*, 223, *Advances from Associated Companies*, and 224, *Other Long-Term Debt*.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. Show premium amounts by enclosing the figures in parentheses.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.
10. Identify separately undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than amortization debited to Account 428, *Amortization of Debt Discount and Expense*, or credited to Account 429, *Amortization of Premium on Debt — Credit*.
12. In a supplemental statement, give explanatory particulars (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, *Interest on Long-Term Debt* and Account 430, *Interest on Debt to Associated Companies*.
16. Give particulars (details) concerning any long term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate *(For new issue, give Commission Authorization numbers and dates)* (a)	Principal Amount of Debt Issued (b)	Total Expense, Premium or Discount (c)	Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)
	First & Refunding Mortgage Bonds:(Acct. 221)								
	Series J, 3 1/4%	$20,000,000	$ 104,478 (192,200)	10/01/52	(a)	10/01/52	(a)	$ - 0 -	$ 487,499
	Series K, 3 1/8%	25,000,000	131,685 (525,800)	05/01/54	05/01/84	05/01/54	05/01/84	25,000,000	781,248
	Series L, 3 1/4%	25,000,000	129,357 (143,750)	06/01/55	06/01/85	06/01/55	06/01/85	25,000,000	812,496
	Series M, 4 1/8%	20,000,000	113,499 (309,600)	10/01/56	10/01/86	10/01/56	10/01/86	20,000,000	825,000
	Series N, 4 1/2%	20,000,000	110,597 60,020*	12/01/57	12/01/87	12/01/57	12/01/87	20,000,000	900,000
	Series O, 3 7/8%	25,000,000	126,012 (38,000)	06/01/58	06/01/88	06/01/58	06/01/88	25,000,000	968,748
	Series P, 4 5/8%	25,000,000	136,836 40,250*	09/01/60	09/01/90	09/01/60	09/01/90	25,000,000	1,156,248
	Series Q, 4 7/8%	30,000,000	150,932 102,000	06/01/61	06/01/91	06/01/61	09/01/91	30,000,000	1,462,500

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec 31, 19 82

LONG-TERM DEBT (Accounts 221, 222, 223, and 224) (Continued)

Line No.	Class and Series of Obligation, Coupon Rate and Commission Authorization (new issue) (a)	Principal Amount of Debt Issued (b)	Total Expense, Premium or Discount (c)	Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)
17	Series R, 4 3/8%	$ 30,000,000	$ 149,329	05/01/63	05/01/93	05/01/63	05/01/93	$ 30,000,000	$ 1,312,500
18			(3,000)						
19	Series S, 4 1/2%	30,000,000	145,516	12/01/63	12/01/93	12/01/63	12/01/93	29,965,000	1,349,271
20			44,700*						
21	Series T, 4 1/2%	60,000,000	247,172	05/01/65	05/01/95	05/01/65	05/01/95	56,600,000	2,692,902
22			458,400*						
23	Series U, 5 1/8%	50,000,000	153,415	02/01/67	02/01/97	02/01/67	02/01/97	49,290,000	2,560,895
24			331,500*						
25	Series V, 6 7/8%	50,000,000	149,678	12/01/67	12/01/97	12/01/67	12/01/97	50,000,000	3,437,496
26			120,500*						
27	Series W, 7 1/8%	85,000,000	228,585	01/01/69	01/01/99	01/01/69	01/01/99	85,000,000	6,056,250
28			(85,850)						
29	Series X, 7 3/4%	75,000,000	213,929	06/01/69	06/01/99	06/01/69	06/01/99	75,000,000	5,812,500
30			656,250*						
31	Series Y, 9 %	85,000,000	254,563	04/01/70	04/01/00	04/01/70	04/01/00	83,725,000	7,535,256
32			743,750*						
33	Series Z, 8 7/8%	85,000,000	246,087	09/01/70	09/01/00	09/01/70	09/01/00	83,725,000	7,430,592
34			850,000*						
35	Series AA, 7 3/8%	90,000,000	268,145	03/01/71	03/01/01	03/01/71	03/01/01	90,000,000	6,637,500
36			(619,930)						
37	Series BB, 7 1/2%	50,000,000	169,391	09/01/71	09/01/01	09/01/71	09/01/01	50,000,000	3,750,000
38			237,000*						
39	Series CC, 7 3/8%	100,000,000	307,580	06/01/72	06/01/02	06/01/72	06/01/02	100,000,000	7,374,996
40			(212,000)						
41	Series DD, 10 1/2%	75,000,000	256,713	07/01/74	07/01/83	07/01/74	07/01/83	75,000,000	7,875,000
42			720,000*						
43	Series EE, 11 %	100,000,000	342,515	07/01/74	07/01/94	07/01/74	07/01/94	71,948,000	8,304,795
44			1,000,000*						
45	Series FF, 11 %	150,000,000	990,038	02/01/75	02/01/94	02/01/75	02/01/94	100,500,000	11,130,625
46	Series GG, 10 %	100,000,000	326,541	11/01/75	11/01/05	11/01/75	11/01/05	100,000,000	9,999,996
47			875,000*						
	Series HH, 9 1/4%	100,000,000	327,870	03/01/76	03/01/06	03/01/76	03/01/06	100,000,000	9,249,996
			875,000*						
	Series II, 8 3/4%	100,000,000	356,994	09/01/76	09/01/06	09/01/76	09/01/06	100,000,000	8,750,004
			1,625,000*						
	Series JJ, 8 5/8%	150,000,000	448,728	03/01/77	03/01/07	03/01/77	03/01/07	150,000,000	12,937,500
			2,437,500*						
	Series KK, 8.95 %	55,000,000	359,706	03/29/78	04/01/98	03/29/78	04/01/98	55,000,000	4,922,496
	Series LL, 9 5/8%	150,000,000	303,795	07/20/78	07/01/08	07/20/78	07/01/08	150,000,000	14,437,500
48			1,312,500*						
49	TOTAL								

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

LONG-TERM DEBT (Accounts 221, 222, 223, and 224) (Continued)

Line No.	Class and Series of Obligation, Coupon Rate and Commission Authorization (new issue) (a)	Principal Amount of Debt Issued (b)	Total Expense, Premium or Discount (c)	Nominal Date of Issue (d)	Date of Maturity (e)	Amortization Period: Date From (f)	Amortization Period: Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)
17	1979 Series A, 10 1/4%	$100,000,000	$ 276,550	04/10/79	04/01/09	04/10/79	04/01/09	$ 99,961,000	$ 10,247,784
18			1,461,000*						
19	1979 Series B, 9.95%	135,000,000	684,261	10/02/79	10/01/04	10/02/79	10/01/04	135,000,000	13,432,500
20	1980 Series A, 12 1/2%	75,000,000	427,822	07/31/80	07/01/00	07/31/80	07/01/00	75,000,000	9,375,000
21									
22	1981 Series A, 15 3/4%	100,000,000	353,922	04/21/81	04/01/89	04/21/81	04/01/89	100,000,000	15,750,000
23	1981 Series B, 15 3/4%		1,000,000*						
24		8,000,000	141,365	07/29/81	07/01/96	07/29/81	07/29/96	8,000,000	1,260,000
25	1981 Series C, 15 3/4%	30,000,000	141,363	(b)	07/01/96	(b)	07/01/96	30,000,000	4,725,000
26	Pollution Control Series								
27	A, (c)	26,000,000	955,045	09/01/75	(c)	09/01/75	09/01/05	26,000,000	2,079,996
28	Pollution Control Series B, 6 3/4%	20,000,000	548,783	05/01/76	05/01/06	05/01/76	05/01/06	20,000,000	1,350,000
29	Pollution Control Series								
30	C, 6.15%	8,000,000	134,541	05/31/78	05/01/03	05/31/78	05/01/03	8,000,000	492,000
31	Pollution Control Series D, 8 3/4%, #PUA820054, 08/30/82	75,000,000	217,197	09/16/82	09/01/12	09/16/82	09/01/12	75,000,000	696,956
32			1,162,500*						
33	Pollution Control Series								
34	E, 8 1/2%, #PUA820111, 12/29/82	15,000,000	150,000*	12/30/82	12/01/02	12/30/82	12/01/02	15,000,000	-
35	Convertible Debentures 3 5/8%	50,000,000	76,903	05/31/78	05/01/03	05/31/78	05/01/86	49,990,000	1,812,132
36			400,000*						
37	Pollution Control Revenue Bonds- Grant County, (d)	22,000,000	344,297	10/01/72	(d)	10/01/72	10/01/02	22,000,000	1,237,500
38	Pollution Control Revenue								
39	Bonds-York County, (d)	29,500,000	954,841	12/01/74	(d)	12/01/74	12/01/04	20,500,000	1,888,922
40	Total Account 221							$ 2,540,224,000	$ 215,299,599
41									
42	*Represents Discount.								
43	() Represents Premium.								
44									
45									
46									
47									
48									
49	TOTAL								

FERC FORM NO. 1 (REVISED 12-81)

Appendix E, Page 3 of 9

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec 31, 19 82

LONG-TERM DEBT (Accounts 221, 222, 223, and 224) (Continued)

Line No.	Class and Series of Obligation, Coupon Rate and Commission Authorization (new issue) (a)	Principal Amount of Debt Issued (b)	Total Expense, Premium or Discount (c)	Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)
17	Term Notes: (Acct. 224)								
18									
19	Ten Year Bank Loan, 8 1/4%	$25,000,000	$ 23,675	05/02/74	(e)	05/02/74	04/30/84	$ 20,000,000	$ 1,810,415
20	Five-Year Bank Loan, (f)	50,000,000	500	01/05/77	(f)	01/05/77	(f)	- 0 -	5,495
21	Term Note, 8 5/8%, (g)	4,500,000	11,250	04/01/77	10/01/83	04/01/77	10/01/83	4,500,000	388,125
	Term Note, 8 5/8%, (g)	500,000	1,250	04/01/77	10/01/83	04/01/77	10/01/83	500,000	43,125
22	Seven-Year Bank Loan, (h)	5,000,000	198	03/01/78	02/28/85	03/01/78	02/28/85	5,000,000	437,503
23	Seven-Year Bank Loan, (h)	15,000,000	593	03/01/78	02/28/85	03/01/78	02/28/85	15,000,000	1,312,501
24	Seven-Year Bank Loan, 8 5/8%	5,000,000	199	03/06/78	03/05/85	03/06/78	03/05/85	5,000,000	431,251
	Ten-Year Bank Loan, (i)	50,000,000	1,976	03/15/78	03/14/88	03/15/78	03/14/88	50,000,000	4,500,002
25	Five-Year Bank Loan, (j)	5,000,000	250	05/08/79	04/30/84	05/08/79	04/30/84	5,000,000	494,999
26	Five-Year Bank Loan, (k)	5,000,000	250	05/08/79	04/30/84	05/08/79	04/30/84	5,000,000	495,067
27	Five-Year Bank Loan, 10 1/4%	10,000,000		06/14/79	06/14/84			10,000,000	1,025,003
	Five-Year Bank Loan, 10 1/4%	4,000,000		06/12/79	06/12/84			4,000,000	415,699
28	Five-Year Bank Loan, 10 1/4%	6,000,000		06/04/79	05/31/84			6,000,000	615,001
29	Five-Year Bank Loan, 10 1/4%	5,000,000	125	07/25/79	07/25/84	07/25/79	07/25/84	5,000,000	512,497
30	Five-Year Bank Loan, 10 1/4%	5,000,000	125	07/27/79	07/27/84	07/27/79	07/27/84	5,000,000	512,497
	Five-Year Bank Loan, 10 1/4%	20,000,000	86,477	12/04/79	12/01/84	12/04/79	12/01/84	20,000,000	2,049,998
31	Five-Year Term Loan, 15.5%	5,000,000	20,000	05/23/80	03/11/85	05/23/80	03/11/85	5,000,000	775,001
32	Four-Year Bank Loan, 11 7/8%	25,000,000	100,083	(l)	(l)	(l)	(l)	25,000,000	3,009,986
33	Five-Year Bank Loan, 15 1/4%	15,000,000	246	05/06/80	03/11/85	05/06/80	03/11/85	15,000,000	2,287,502
	Five-Year Bank Loan, 11 7/8%	15,000,000	250	07/02/80	05/16/85	07/02/80	05/16/85	15,000,000	1,805,989
34	Seven-Year Bank Loan, 14 1/2%	10,000,000	1,734	04/01/80	04/01/87	04/01/80	04/01/87	10,000,000	1,450,001
35	Fifteen-Year Bank Loan, 12 3/8%	10,000,000	60,065	07/28/80	07/28/95	07/28/80	07/28/95	10,000,000	1,237,500
	Three-Year Bank Loan, 11 3/8%	5,000,000	250	09/30/80	(m)	09/30/80	(m)	2,500,000(m)	511,087
36	Project Financing Liability, (n)	250,000,000	985,182	06/17/80	12/31/83	06/17/80	(n)	250,000,000	31,799,671
37	Pollution Control Note - Chesterfield, (o)	40,000,000	219,325	12/10/80	(o)	12/10/80	(o)	- 0 -	- 0 -
38	Three-Year Pollution Control								
39	Note, 8.55%	6,000,000		04/01/81	02/01/84			6,000,000	527,250
40	Four-Year Bank Loan, (p)	50,000,000	7,386	11/25/81	10/14/85	04/01/82	10/14/85	50,000,000	7,695,488
41									
42									
43									
44									
45									
46									
47									
48									
49	TOTAL								

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

LONG-TERM DEBT (Accounts 221, 222, 223, and 224) (Continued)

Line No.	Class and Series of Obligation, Coupon Rate and Commission Authorization (new issue) (a)	Principal Amount of Debt Issued (b)	Total Expense, Premium or Discount (c)	Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)
17									
18	Three-Year Bank Loan, (q)	$25,000,000	$ 3,695	12/22/81	(q)	04/01/82	(q)	$ - 0 -	$ 1,759,876
19	Four-Year Bank Loan, (r)	50,000,000	3,695	12/22/81	12/22/85	04/01/82	12/22/85	50,000,000	5,932,653
20									
21	Three-Year Bank Loan, (s)	25,000,000	3,694	12/18/81	12/01/84	04/01/82	12/01/84	25,000,000	3,657,169
22	Three-Year Bank Loan, (s)	25,000,000	3,691	12/18/81	11/09/84	04/01/82	11/09/84	25,000,000	3,424,721
23									
24	Chesterfield Pollution Control Note, (t)	25,000,000	107,079	12/31/81	10/31/84	01/01/82	10/31/84	11,000,000	-
26	Chesterfield Pollution Control Note, (u)								
26	#PUA820077, 10/19/82	5,000,000	31,158	10/01/82	09/30/85	10/01/82	09/30/85	5,000,000	2,182
27									
28	Total Account 224							$ 664,500,000	$ 80,925,254
29									
30	Total Long-Term Debt							$ 3,204,724,000	$296,224,853
31									
32									
33									
34									
35									
36									
37									
38									
39									
40									
41									
42									
43									
44									
45									
46									
47									
48									
49	TOTAL								

LONG-TERM DEBT (ACCOUNTS 221, 222, 223, and 224)

Notes to Pages 256 and 257

(a) Retired 10/01/82.

(b) $20,000,000 issued on 07/29/81 and $10,000,000 issued on 10/06/81.

(c) Interest rates and maturity dates are as follows: $8,000,000 Bond, 6 7/8% due September 1, 1985 and $18,000,000 Bond 8 1/2% due September 1, 2005.

(d) Pollution Control Revenue Bonds:

Principal Amount	Maturity	Interest Rate	Mandatory Sinking Fund Requirements: Annual Amount	Mandatory Sinking Fund Requirements: Period
$ 2,000,000	Dec. 1983	7.4%	None	
4,000,000	Dec. 1989	8.0	$250,000	1981-1983
			500,000	1984-1986
			750,000	1987-1989
22,000,000	Oct. 2002	5 5/8	500,000	1990-2001
14,500,000	Dec. 2004	8 3/4	750,000	1990-2003
$42,500,000				

(e) Will mature in installments of: $10,000,000 due 04/30/83 and $10,000,000 due 04/30/84.

(f) Retired 01/04/82.

(g) Seven and one-half year bank loan exchanged for $4,500,000 and $500,000 term notes on 04/01/77.

(h) Cost of money equal to 115% of the bank's prime lending rate in effect from time to time and not to exceed an average of 8.75% over the seven-year period.

(i) Cost of money will be equal to 118% of the higher of (a) the Chase prime rate or (b) the average weekly rate for 90-119 day prime commercial paper placed through dealers plus 1/2 of 1%, with an average cap of 9.00% and an average floor of 8%.

(j) Cost of money equal to 115% of the bank's prime lending rate in effect from time to time and not to exceed an average of 9.9% over the five-year period.

(k) Cost of money will be equal to 107.5% of the bank's prime lending rate not to exceed an average of 9.9% over the five-year period.

(l) $21,000,000 issued 07/14/80 and due 08/14/84; $4,000,000 issued 07/23/80 and due 07/23/84.

(m) Maturity dates: $1,250,000 due March 30, 1983, and $1,250,000 due September 30, 1983.

(n) On June 17, 1980, the Company established the Bath County Hydroelectric Trust to finance up to $220 million in construction costs for the Bath County Pumped Storage Project.

The amount was renegotiated in August, 1981 to $250,000,000. On June 17, 1980, the Trust contracted with Bath County Hydroelectric, Inc., a special purpose corporation established for the sale of commercial paper. The Trust may obtain funds by receiving the proceeds from the commercial paper borrowings of the corporation, or, if the terms are more favorable, the Trust may obtain funds by borrowing Eurodollars directly from certain banks participating in a revolving credit loan agreement. The proceeds of the borrowings from the trust will be used to reimburse the Company for construction expenditures and AFC incurred since January 1, 1980, and will also provide funds to make interest payments. The initial term of the letter of credit, which supports the commercial paper, and the initial term of the revolving credit loan arrangement will expire December 31, 1985. The Company unconditionally guarantees the borrowings of the Trust.

The cost of the commercial paper will be the market rate plus a customary discount to the dealers. The principal fees and costs relating to the revolving credit loan arrangement are (i) a support fee of 5/8% per annum on the daily average amount of commercial paper outstanding and supported by the letter of credit, (ii) a commitment fee of 1/2% per annum on the unused portion of the credit commitment, computed on a daily average basis, (iii) an interest rate of 110% of the London Inter-Bank Offering Rate (the LIBO

Rate) for any revolving credit loans and (iv) reimbursement of certain reserve and other costs and taxes (other than income taxes) which may be imposed on any of the banks in connection with this arrangement.

(o) Retired 09/16/82.

(p) The interest rate is renegotiated every six months based on Citibank's cost of money not to exceed 17 1/2%.

(q) Retired 06/21/82.

(r) The interest rate is renegotiated every six months based on Citibank's cost of money not to exceed 17 1/2%.

(s) The interest rate is renegotiated every six months based on Bankers' Trust' cost of money not to exceed 17 1/2%.

(t) The rate of interest on these funds is 65% of the Chase Manhattan prime not to exceed a cap rate of 11%.

(u) The rate of interest on these funds is 65% of the Chase Manhattan prime not to exceed a cap rate of 11%.

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec 31, 1982

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.

2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.

3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.

4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

(Continued on page 259.)

Line No.	Kind of Tax (See Instruction 5) (a)	Balance at Beginning of Year: Taxes Accrued (b)	Balance at Beginning of Year: Prepaid Taxes (c)	Taxes Charged During Year (d)	Paid During Year (e)	Adjustments (f)	Balance at End of Year: Taxes Accrued (Account 236) (g)	Balance at End of Year: Prepaid Taxes (Incl. in Account 165) (h)
1	Federal							
2								
3	Income	$59,653,076		$11,145,366	$15,808,420	$(3,189,802)	$51,800,220	$
4								
5								
6	Excise							
7	Unemployment Insurance	51,134		579,400	563,852		66,682	
8	Old Age Benefits	318,676		19,129,000	18,989,132		535,735	
9	Medical Insurance Benefits	77,191						
10								
11	State-Virginia							
12	Gross Receipts	7,308,126	$28,963,923	53,083,519	47,307,082		9,089,631	24,968,991
13	Valuation	198,900		3,396,653	3,330,074		265,479	
14	Sales and Use	75,084		1,306,600	1,245,644		136,010	
15	Unemployment Insurance	33,534		648,100	610,588		71,046	
16	Miscellaneous			161,464	164,461			
17								
18	State-West Virginia							
19	Gross Receipts	60,342		630,198	633,138		57,402	
20	Business & Occupation	903,248		9,381,385	9,492,773		791,860	
21	License			1,385	4,385			
22	Public Service Com. Special			138,273	138,273			
23	Property	7,256		13,879	14,070		7,065	
24	Unemployment Insurance	23,336		392,200	374,010		41,526	
25	Miscellaneous	2,001		6,684	7,685		1,000	
26	Income	-0-		14,158			14,158	
27								
28								

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. *If any tax (exclude Federal and state income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (a).*

6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. Designate debit adjustments by parentheses.

7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.

8. Enter accounts to which taxes charged were distributed in columns (i) thru (l). In column (i), report the amounts charged to Accounts 408.1 and 409.1 for Electric Department only. Group the amounts charged to 408.1, 409.1, 408.2 and 409.2 under other accounts in column (l). For taxes charged to other accounts or utility plant, show the number of the appropriate balance sheet account, plant account or subaccount.

9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

DISTRIBUTION OF TAXES CHARGED *(Show utility department where applicable and account charged.)*

Line No.	Electric (Account 408.1, 409.1) (i)	Gas (Account 408.1 409.1)	Other Income & Deductions (Account 408.2 409.2)	Electric Account 107	Electric Account 108	Account 163	Account 182	Account 184	Other
1									
2									
3	$ (8,391,897)	$ (70,915)	$16,985,073						$2,623,105
4									
5									
6									
7	363,955	12,152		$ 176,057	$ 6,855	$ 11,375		$ 4,738	4,268
8	12,939,769	428,230		4,739,017	197,510	356,108		151,690	316,676
9									
10									
11									
12	50,518,889	2,564,618	12						
13	3,241,018	155,634	1						
14	754,496	31,437		410,053			$ 110,614		
15	405,525	15,320		196,346	7,661	12,624		5,293	5,331
16	157,891	6,573							
17									
18									
19	630,198								
20	9,381,385								
21	4,385								
22	138,273								
23	13,879								
24	269,006			107,746	4,478	7,710		3,260	
25	6,684								
26	14,158								
27									
28									

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1982

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.

2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.

3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.

4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

(Continued on page 259.)

Line No.	Kind of Tax (See Instruction 5)	Balance at Beginning of Year		Taxes Charged During Year	Paid During Year	Adjustments	Balance at End of Year	
		Taxes Accrued	Prepaid Taxes				Taxes Accrued (Account 236)	Prepaid Taxes (Incl. in Account 166)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1								
2	State - North Carolina							
3	Income	$ 400,548		$ 147,502	$ 462,435		$ 322,201	$ 236,586
4	Gross Receipts			9,892,601	9,892,601			
5	Unemployment Insurance	1,421		18,700	18,780		1,341	
6	Miscellaneous	8,000		14,161	15,164		7,000	
7								
8	Local - Virginia							
9	Property			33,856,195	33,830,360		25,835	
10	Gross Receipts	709,771		6,675,161	6,759,209		625,723	
11	Poles and Conduits	9,034		65,701	65,680		9,019	
12								
13	Local - West Virginia							
14	Property	4,877,029		3,471,547	3,273,129		5,075,447	
15	Gross Sales	12,763		58,503	58,386		12,880	
16	Miscellaneous			15	15			
17								
18	Local - North Carolina							
19	Property			1,821,015	1,821,045			
20	Miscellaneous			100	100			
21								
22	Local - Maryland							
23	Property			103,000	180		102,820	
24								
25								
26								
27								
28	TOTAL	$ 74,730,470	$28,963,923	$156,158,493	$154,880,689	$(3,189,802	$ 69,060,140	$25,205,577

Page 258-1

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec 31, 19 82

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. *If any tax (exclude Federal and state income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (a).*

6. **Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. Designate debit adjustments by parentheses.**

7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.

8. Enter accounts to which taxes charged were distributed in columns (i) thru (l). In column (i), report the amounts charged to Accounts 408.1 and 409.1 for Electric Department only. Group the amounts charged to 408.1, 409.1, 408.2 and 409.2 under other accounts in column (l). For taxes charged to other accounts or utility plant, show the number of the appropriate balance sheet account, plant account or subaccount.

9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

DISTRIBUTION OF TAXES CHARGED *(Show utility department where applicable and account charged.)*

Line No.	Electric (Account 408.1, 409.1) (i)	Gas (Account 408.1 409.1)	Other Income & Deductions (Acct. 408.2 409.2)	Electric Account 107	Electric Account 108	Account 163	Account 182	Account 184	Other
1									
2									
3	$ (54,930)		$ 202,432						
4	9,892,601								
5	14,638			$ 3,257	$ 216	$ 382		$ 157	
6	14,164								
7									
8									
9	30,084,529	$ 646,140	115,276	1,239,177		47,693	$ 515,809	566,907	$ 640,664
10	6,243,048	432,113							
11	65,701								
12									
13									
14	3,471,374								173
15	58,503								
16	15								
17									
18									
19	1,788,249					1,247		31,549	
20	100								
21									
22									
23	103,000								
24									
25									
26									
27									
28	$122,128,656	$ 4,221,302	$17,302,794	$6,871,653	$ 216,720	$ 437,139	$ 626,423	$ 763,594	$3,590,217

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Elec. & Power Co.	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.

2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group members, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.

3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		
6	See Page 261-A and 261-B	
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	

28 Show Computation of Tax: Note A

Virginia Electric and Power Company and its wholly owned subsidiaries, Laurel Run Mining Company and Virginia Nuclear, Inc. will file a consolidated tax return for 1982. There are no intercompany eliminations to be made in the consolidated tax return. The effect in tax for 1982 attributable to the inclusion of Laurel Run Mining Company and Virginia Nuclear, Inc. in the consolidated return is estimated to be an increase in tax of $2,684,687 relating to Laurel Run and a decrease in tax of $136 relating to Virginia Nuclear. The allocation of the consolidated tax amount is on the basis of separate returns before any tax credits allocated to the member that originates them. Any reduction in tax resulting from deductions and credits in excess of income on a separate return basis availed of in the consolidated return is paid, or credited, to the member which originated the deductions or credits.

VIRGINIA ELECTRIC AND POWER COMPANY
RECONCILIATION OF REPORTED NET INCOME PER BOOKS WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

Net Income for the Year		$278,589,158
Reconciling Items for the Year:		
Taxable Income Not Reported on the Books:		
Refund on Long Term Bank Loan	$ 12,475,314	
Long Term Capital Gain Adjustment	32,011,020	
Customer Accounts Reserve	4,591,312	
		49,077,646
Expenses Recorded on Books Not Deducted on Return:		
Federal Income Tax - Net Current	(8,462,812)	
Taxes Deferred - Net	171,491,247	
Investment Tax Credit - Net of Amortization	(10,109,873)	
Federal Income Taxes Charged Other Income and Deductions	14,776,125	
Utility Plant Acquisition Adjustment	18,408	
Amortization of Property Loss	21,220,648	
Excess Amount Expensed on Books Over Amount Allowable on Return -		
Virginia Gross Receipts	3,977,463	
Leased Turbine Expense Included in Production Expense Exclusive of Depreciation	(1,396,720)	
Penalties	52,667	
AFDC Capitalized to Nuclear Fuel Inventories Charged Fuel Expense Per Books	4,519,578	
Property Taxes Capitalized to Nuclear Fuel Inventories Charged Fuel Expense Per Books	73,581	
Interest on Customer Accounts Reserve	759,973	
Deferred Fuel-Preliminary Operations	3,343,957	
Reprocessing Costs on Nuclear Fuel (Gross)	16,507,385	
North Carolina Permanent Disposal Costs	1,067,033	
FERC & MS Permanent Disposal Costs	5,344,119	
West Virginia Permanent Disposal	217,367	
North Anna #2 Commercial Operations	16,054,355	
North Anna #1 Commercial Operations Fuel Expense	11,307,720	
Surry Owned Fuel Expense	7,439,028	
Surry Leased Fuel	48,847,439	
Deferred Fuel-Surry Leased Westinghouse	2,806,237	
Amortization of Premium Discount Debt & Expense	(2,668,493)	
Interest Expense on Return Earned on Decommissioning	704,179	
Depreciation-Seventh & Franklin Bldg.	113,124	
Executive Supplemental Retirement Plan	206,963	
Customer Stock Purchase Plan-Interest	40,167	
N. C. Municipal Power Sale	(6,000)	
Deferred Hospitalization Insurance Premiums	518,000	
Bad Debts	(157,648)	
Spare Parts Inventory Adjustment - Net	2,181,919	
Transfer of Implosion Costs	516,821	
Amortization of Yorktown	117,657	
Injuries and Damages Reserve	204,204	
1981 N. C. Adjusting Entry	19,088	
ESOP Administrative Expenses - Prior Year	61,284	
		311,706,190
Income Recorded on Books Not Included in Return:		
Allowance for Other Funds Used During Construction	43,863,050	
Allowance for Borrowed Funds Used During Construction	39,510,148	
Sale/Leaseback - District Office Buildings	107,940	
- Land for System Office Building	53,880	
Interest Income on Pollution Control Issues-Net	890,774	
		84,425,792

VIRGINIA ELECTRIC AND POWER COMPANY
RECONCILIATION OF REPORTED NET INCOME PER BOOKS WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

60	Deductions on Return Not Charged Against Book Income:		
61	Excess of Tax Over Book Depreciation	$150,670,369	
62	Taxes Capitalized	7,248,786	
63	Thrift Plan Costs Capitalized	934,165	
64	Pension Plan Costs Capitalized	3,735,414	
65	State and Local Recording Tax on Bonds	67,202	
66	Excess Amount Deductible on Return Over Amount		
67	Expensed on Books -		
68	Cost of Removal Charged Depreciation Reserve		
69	Per Books	11,317,726	
70	Repair Expenses	(179,962)	
71	Variable Prime Interest on Bank Loans	6,049,879	
72	Laurel Run Equity Portal #1	2,604,152	
73	Surry #3 & 4 Property Loss	176,279	
74	North Anna #3 Property Loss	317,030,022	
75	North Anna #4 Property Loss	380,264	
76	Net Deferred Fuel Expense	(21,616,445)	
77	Capitalized Finance Costs Surry Leased		
78	Nuclear Fuel	1,696,316	
79	Deferred Fuel Reprocessing Costs	392,298	
80	Deferred Fuel Expense Surry Owned	1,051,305	
81	Deferred Fuel - Surry Leased Nuclear Fuel	11,267,686	
82	Deferred Fuel - North Anna #1 Fuel Expense	3,311,536	
83	North Anna #2 Commercial Operations		
84	Deferred Fuel	(2,020,839)	
85	Refund on FERC & MS Reserve	5,876,216	
86	Westinghouse Settlement - Surry Batch #7	13,120,870	
87	Westinghouse Settlement North Anna #1 Batch #4	3,773,567	
88	Customer Stock Purchase Plan -		
89	Interest (1982)	49,777	
90	Nuclear Facilities Sale to Coop	132,744	
91	R & D Expenditures	1,130,083	
92			$518,199,410
93	Taxable Income Before Special Deduction		36,747,792
94	Special Deduction - Preferred Dividend Credit		425,877
95	Federal Taxable Income		$36,321,915
96	Computation of Tax:		
97	Federal Taxable Income	$36,321,915	
98	Less: Capital Gain Items	53,095,771	
99	Income Taxable at Ordinary Rates	(16,773,856)	
100	Tax @ 17% x $25,000		
101	Tax @ 20% x $25,000		
102	Tax @ 30% x $25,000		
103	Tax @ 40% x $25,000		
104	Tax @ 46% x		$(5,507,214)
105	Tax @ 46% Ordinary Loss		13,522,353
106	Tax Liability		8,015,139
107	Adjustment 1968-1978 IRS		(6,509,983)
108	Tax Liability - Other - Adjustment for 1981 Return		(2,627,139)
109	Bath County Differential		8,692,942
110	Total Current Taxes Before Investment Tax Credit		7,570,959
111	Reduction - Investment Tax Credit		951,302
112	Net Current Taxes Charged Income		$ 8,522,261
113	To Operating Income		$(8,462,812)
114	To Other Income Deductions		$16,985,073

Refer to Note A, Page 261 for description of Consolidated Tax Return Information.

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1982

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Contra Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Contra Account No (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)
1	Electric Utility								
2	3%	$ 122,775	411.4	$ 43,071	411.4	$ (49,708)	$	116,138	30 years
3	4%	47,304,251	411.4	(2,747,052)	411.4	(3,611,788)		40,945,411	30 years
4	7%								
5	10%	60,625,794	411.4	5,176,907	411.4	(5,357,704)		60,444,997	30 years
6									
7									
8	TOTAL	108,052,820		2,472,926		(9,019,200)		101,506,546	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)								
10	Gas Utility								
11									
12	3%	699			411.4	(30)		669	35 years
13	4%	317,908			411.4	(11,945)		305,963	35 years
14	7%								
15	10%	1,275,427	411.4	364,528	411.4	(43,788)		1,596,167	35 years
16									
17	Total	1,594,034		364,528		(55,763)		1,902,799	
18									
19	Grand Total	$ 109,646,854		$ 2,837,454		$ (9,074,963)		$ 103,409,345	
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32									

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $10,000, whichever is greater) may be grouped by classes.

Line No.	Description of Other Deferred Credit (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Virginia Railway & Power					
2	Co. preferred script					
3	to be exchanged	$ 1,649				$ 1,649
4						
5	Liability for replacement					
6	of leased property					
7	removed - Norfolk					
8	Southern Railway	360,459				360,459
9						
10	Refunds from Commonwealth					
11	Natural Gas Corp. on					
12	purchase of natural gas	2,389,492	804	3,300,092	1,938,032	1,027,432
13						
14	Provision for leveling					
15	payment rentals -					
16	leased turbines (b)	19,827,703	550	1,379,972		18,447,731
17						
18						
19	Unamortized gain on sale					
20	of Company buildings(a)	1,403,220	421.1	107,940		1,295,280
21						
22	Westinghouse Settlement	160,913,918	518	68,080,174	65,288,541	158,122,285
23	(b)					
24	Incremental Gas Charges	52,536	804	48,541	104,452	108,447
25						
26	No. Virginia Regional					
27	Park Authority	50,000		50,000		-0-
28						
29	Acc. Provision Nuclear					
30	Decommissioning Costs	6,153,901			898,182	7,052,083
31						
32	Accumulated Provision					
33	for Disposal Costs -					
34	Present Worth N.C.	8,401,364	518	404,873	2,290,131	10,286,622
35						
36	Executive Supplemental					
37	Retirement Plan	460,259	242	42,496	257,201	674,964
38						
39	Stone & Webster					
40	Agreement	5,000,000		4,331,772		668,228
41						
42	(a) Period of amortization: January 1975 through December 1994.					
43	(b) Refer to Notes to Financial Statements, pages 26-35 in the Company's 1982					
44	Annual Report to Stockholders attached, which notes are incorporated herein					
45	by reference.					
46						
47	TOTAL					

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $10,000, whichever is greater) may be grouped by classes.

Line No.	Description of Other Deferred Credit (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	APS Option Payments -					
2	Bath County	$ -0-			$18,860,208	$18,860,208
3						
4	Option Payments - Pig					
5	Point Property	-0-			35,000	35,000
6						
7	Payment Litigation -					
8	Hinson Grady					
9						
10	Construction Co.	-0-		898	20,359	19,461
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
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24						
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41						
42						
43						
44						
45						
46						
47	TOTAL	$205,014,501				$216,959,849

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Elec. & Power Co.	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

ACCUMULATED DEFERRED INCOME TAXES—ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amortizable property.
2. For Other *(Specify)*, include deferrals relating to other

Line No	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities	$ 8,488,296		$ 1,496,040
4	Pollution Control Facilities			
5	Other			
6				
7				
8	TOTAL Electric *(Enter Total of lines 3 thru 7)*	$ 8,488,296		$ 1,496,040
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other			
13				
14				
15	TOTAL Gas *(Enter Total of lines 10 thru 14)*			
16	Other *(Specify)*			
17	TOTAL (Account 281) *(Enter Total of 8, 15 and 16)*	$ 8,488,296		$ 1,496,040
18	Classification of TOTAL			
19	Federal Income Tax	$ 8,488,296		$ 1,496,040
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric & Power Co	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

ACCUMULATED DEFERRED INCOME TAXES–ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

income and deductions.

3. Use separate pages as required.

CHANGES DURING YEAR: Amounts Debited (Account 410.2) (e)	CHANGES DURING YEAR: Amounts Credited (Account 411.2) (f)	ADJUSTMENTS Debits: Acct. No. (g)	ADJUSTMENTS Debits: Amount (h)	ADJUSTMENTS Credits: Acct. No. (i)	ADJUSTMENTS Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						$ 6,992,256	3
							4
							5
							6
							7
						$ 6,992,256	8
							9
							10
							11
							12
							13
							14
							15
							16
						$ 6,992,256	17
							18
						$ 6,992,256	19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric & Power Co	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

ACCUMULATED DEFERRED INCOME TAXES—OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.
2. For Other *(Specify)*, include deferrals relating to other

Line No.	Account Subdivisions *(a)*	Balance at Beginning of Year *(b)*	CHANGES DURING YEAR Amounts Debited (Account 410.1) *(c)*	Amounts Credited (Account 411.1) *(d)*
1	Account 282			
2	Electric	$ 235,481,732	$62,395,395	$1,354,067
3	Gas	1,372,283	723,375	9,071
4	Other *(Define)*			
5	TOTAL *(Enter Total of lines 2 thru 4)*	$ 236,854,015	$63,118,770	$1,363,138
6	Other *(Specify)*			
7				
8				
9	TOTAL Account 282 *(Enter Total of lines 5 thru 8)*	$ 236,854,015	$63,118,770	$1,363,138
10	Classification of TOTAL			
11	Federal Income Tax	$ 236,854,015	$63,118,770	$1,363,138
12	State Income Tax			
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric & Power Co	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

ACCUMULATED DEFERRED INCOME TAXES—OTHER PROPERTY (Account 282) (Continued)

income and deductions.
3. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
$ 18,887				(1)(2)	$ 1,664,055	$294,877,892	2
						2,086,587	3
							4
$ 18,887					$ 1,664,055	$296,964,479	5
							6
							7
							8
$ 18,887					$ 1,664,055	$296,964,479	9
							10
$ 18,887					$ 1,664,055	$296,964,479	11
							12
							13

NOTES (Continued)

Adjustments are made up as follows:

(1) Credit to Account 410.2 of $848,291 to reverse Taxes Capitalized and Benefit Plan Costs relating to the sale of 20% of Bath County.
(2) Credit to Account 283 of $815,764 to transfer the income portion of deferred taxes from taxes capitalized to NA #3 Property Loss.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric & Power Co	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

ACCUMULATED DEFERRED INCOME TAXES—OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For Other (*Specify*), include deferrals relating to other

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	CHANGES DURING YEAR Amounts Credited (Account 411.1) (d)
1	Account 283			
2	Electric			
3				
4	See Page 273 A			
5				
6				
7				
8	Other			
9	TOTAL Electric (*Enter Total of lines 2 thru 8*)			
10	Gas			
11				
12				
13				
14				
15				
16	Other			
17	TOTAL Gas (*Enter Total of lines 10 thru 16*)			
18	Other (*Specify*)			
19	TOTAL Account 283 (*Enter Total of lines 9, 17 and 18*)			
20	Classification of TOTAL			
21	Federal Income Tax			
22	State Income Tax			
23	Local Income Tax			

NOTES

Provide in the space below explanations for pages 272 and 273.
Include amounts relating to insignificant items under Other.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Elec. & Power Co.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

ACCUMULATED DEFERRED INCOME TAXES—OTHER (Account 283) (Continued)

income and deductions.

3. Use separate pages as required.

Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	ADJUSTMENTS Debits Acct. No. (g)	ADJUSTMENTS Debits Amount (h)	ADJUSTMENTS Credits Acct. No. (i)	ADJUSTMENTS Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
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							22
							23

NOTES (Continued)

VIRGINIA ELECTRIC AND POWER COMPANY
YEAR ENDED DECEMBER 31, 1982
ACCUMULATED DEFERRED INCOME TAXES - OTHER (ACCOUNT 283)
Ferc Form I Pages 272-273

Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During The Year: Amt. Debited (Acct. 410.1) (c)	Amt. Credited (Acct. 411.1) (d)	Amt. Debited (Acct. 410.2) (e)	Amt. Credited (Acct. 411.2) (f)	Adjustments: Debits: Acct. No. (g)	Amount (h)	Credits: Acct. No. (i)	Amount (j)	Balance at End of Year (k)
Electric:										
Virginia Gross Receipts	$ 13,019,856	$ (1,841,602)								$ 11,178,254
Property Loss	73,383,778	133,342,532	$ 8,014,589			282	$815,764			199,527,485
Deferred Fuel Adjustment	45,709,555	37,282,850	26,253,193					283	$ 6	56,739,206
Reprocessing Costs on Nuclear Fuel	(31,208,975)		10,959,922							(42,168,897)
Nuclear Fuel Owned	(3,362,321)		4,946,384							(8,308,705)
Permanent Disposal Costs - N.C.	(3,183,126)		490,835							(3,673,961)
Permanent Disposal Costs - FERC	(12,624,973)		2,458,295							(15,083,268)
Permanent Disposal Costs - W.Va.	-0-		99,989							(99,989)
Preliminary Operations	(4,098,097)	335,454	5,615,798			283	6			(9,378,435)
Spare Parts Inventory	1,003,682	(1,003,682)								-0-
Variable Prime Interest	2,273,935	1,854,821								4,128,756
Customer Accounts Reserve	(812,036)		(241,987)							(570,049)
Yorktown Implosion Costs	-0-			$ 4,242						4,242
Total Electric	$ 80,101,278	$ 169,970,373	$ 58,597,018	$ 4,242			$ 815,770		$ 6	$ 192,294,639
Gas:										
Virginia Gross Receipts	406,900	(59,982)								346,918
Deferred Fuel Adjustment	132,756	170,383	354,242							(51,103)
Variable Prime Interest	18,800	16,845								35,645
Total Gas	$ 558,456	$ 127,246	$ 354,242							$ 331,460
Total Account 283	$ 80,659,734	$ 170,097,619	$ 58,951,260	$ 4,242			$ 815,770		$ 6	$ 192,626,099
Classification of Total:										
Federal Income Tax	$ 80,659,734	$ 170,097,619	$ 58,951,260	$ 4,242			$ 815,770		$ 6	$ 192,626,099
State Income Tax										
Local Income Tax										

FERC FORM NO. 1 (REVISED 12-81) Page 301

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If previous year (columns (c), (e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
4. *Commercial and Industrial Sales*, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
5. See page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.
6. For lines 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by accounts.
7. Include unmetered sales. Provide details of such sales in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES: Amount for Year (b)	OPERATING REVENUES: Amount for Previous Year (c)	MEGAWATT HOURS SOLD: Amount for Year (d)	MEGAWATT HOURS SOLD: Amount for Previous Year (e)	AVG. NO. OF CUSTOMERS PER MONTH: Number for Year (f)	AVG. NO. OF CUSTOMERS PER MONTH: Number for Previous Year (g)
1	Sales of Electricity						
2	(440) Residential Sales	$ 886,175,187	$ 814,152,360	13,271,899	13,399,471	1,247,299	1,223,874
3	(442) Commercial and Industrial Sales						
4	Small (or Commercial) *(See Instr. 4)*	592,117,895	541,263,563	9,885,719	9,816,267	125,006	122,630
5	Large (or Industrial) *(See Instr. 4)*	309,631,525	261,825,008	6,976,832	6,415,945	907	920
6	(444) Public Street and Highway Lighting	18,580,683	17,589,604	183,370	179,878	1,063	1,028
7	(445) Other Sales to Public Authorities	219,575,920	199,455,409	4,950,368	4,795,096	17,109	16,256
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	2,026,081,210	1,834,285,944	35,268,188	34,606,657	1,391,384	1,364,708
11	(447) Sales for Resale	208,992,501	219,617,831	4,712,059	5,299,685	31	40
12	TOTAL Sales of Electricity	2,235,073,711*	2,053,903,775	39,980,247 **	39,906,342	1,391,415	1,364,748
13	Other Operating Revenues						
14	(450) Forfeited Discounts	5,286,701	4,724,950				
15	(451) Miscellaneous Service Revenues	9,547,102	8,224,179				
16	(453) Sales of Water and Water Power	3,435	3,307				
17	(454) Rent from Electric Property	2,235,605	2,242,954				
18	(455) Interdepartmental Rents						
19	(456) Other Electric Revenues	2,379,720	665,099				
20							
21							
22							
23							
24	TOTAL Other Operating Revenues	19,452,563	15,860,489				
25	TOTAL Electric Operating Revenues	$2,254,526,274	$2,069,764,264				

*Includes $ (10,556,148) unbilled revenues. (Net)

**Includes (361,464) MWH relating to unbilled revenues. (Net)

Next Page is 304

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric & Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the kWh of electricity sold, revenue, average number of customers, average kWh per customer, and average revenue per kWh, excluding data for Sales for Resale is reported on pages 310-311.

2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," page 301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.

3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.

4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).

5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.

6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales per Customer (e)	Revenue per KWh Sold (f)
1						
2	440.0 Residential Sales					CENTS
3	1	3,751,069	$273,578,292	549,414	6,827	7.29
4	2	9,277,054	594,231,116	679,431	13,654	6.41
5	3	76,365	4,854,942	6,508	11,734	6.36
6	4	8,692	529,489	634	13,710	6.09
7	17	1,844	71,546	(A) 580	3,179	3.88
8	18	475	28,372	33	14,394	5.97
9	20	1	56	1	1,000	5.60
10	21	9	609	6	1,500	6.77
11	22	-0-	2	1	-0-	-0-
12	23	11	754	17	647	6.85
13	26	26,174	2,579,980	(A) 31,156	840	9.86
14	70	46,678	3,012,167	2,111	22,112	6.45
15	72	186,863	11,363,154	6,423	29,093	6.08
16	74	1,008	45,165	125	8,064	4.48
17	75	547	55,402	(A) 125	4,376	10.13
18	76	5,089	179,400	350	14,540	3.53
19	77	2,413	251,244	(A) 350	6,894	10.41
20	84	10,719	368,051	627	17,096	3.43
21	85	7,011	596,779	(A) 628	11,164	8.51
22	86	38,738	1,236,608	1,618	23,942	3.19
23	87	23,734	2,048,059	(A) 1,618	14,669	8.63
24	UNBILLED	(192,595)	(8,856,000)			
25	TOTAL 440.0	13,271,899	886,175,187	1,247,299	10,641	6.68
26						
27						
28	442.1 Commercial Sales					
29	5	4,343,148	305,150,058	117,249	37,042	7.03
30	5P	1,479	73,236	7	211,286	4.95
31	6	5,389,332	274,029,449	3,138	1,717,442	5.08
32	7	17,947	938,840	(A) 734	24,451	5.23
33	8	43,262	2,304,776	(A) 2,154	20,084	5.33
34	9	99,237	7,846,296	4,602	21,564	7.91
35	26	67,800	5,244,380	(A) 23,467	2,889	7.74
36	78	458	13,342	10	45,800	2.91
37	79	290	33,518	(A) 10	29,000	11.56
38	UNBILLED	(77,234)	(3,516,000)			
39	TOTAL 442.1	9,885,719	592,117,895	125,006	79,082	5.99
40						
41	Total Billed					
42	Total Unbilled Rev. *(See Instr. 6)*					
43	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric & Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the kWh of electricity sold, revenue, average number of customers, average kWh per customer, and average revenue per kWh, excluding data for Sales for Resale is reported on pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," page 301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales per Customer (e)	Revenue per KWh Sold (f)
1						CENTS
2	442.2 Industrial Sales					
2	5	259,759	$ 18,786,326	430	604,091	7.23
3	6	6,795,860	293,568,533	476	14,277,017	4.32
4	8	2	152 (A)	1	2,000	7.60
5	10	(27,935)	(965,919)	1	(27,935,000)	(3.46)
6	26	3,104	234,433 (A)	259	11,985	7.55
7	UNBILLED	(53,958)	(1,992,000)			
8	TOTAL 442.2	6,976,832	309,631,525	907	7,692,207	4.44
9						
10						
11	444.1 Public Street &					
12	Highway Lighting	159,234	17,460,310	805	197,806	10.97
13						
14	444.2 Traffic & Other					
15	Signal Systems	24,136	1,120,373	258	93,550	4.64
16	TOTAL 444	183,370	18,580,683	1,063	172,502	10.13
17						
18	445.0 Other Sales To					
19	Public Authorities					
20						
21	NASA	217,600	9,690,603	1	217,600,000	4.45
22	MS	1,979,151	79,066,532	52	38,060,596	3.99
23	MS Reserve		277,691			
24	State & Local Gov. Misc					
25	Light & Power	2,794,026	127,151,903	17,056	163,815	4.55
26	UNBILLED	(40,409)	3,389,191			
27	TOTAL 445.0	4,950,368	219,575,920	17,109	289,343	4.44
28						
29	TOTAL SALES	35,268,188	2,026,081,210	1,391,384	25,348	5.74
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	Total Billed	35,632,384	2,037,056,019	1,391,384	25,609	5.72
42	Total Unbilled Rev. *(See Instr. 6)*	(364,196)	(10,974,809)			
43	TOTAL	35,268,188	2,026,081,210	1,391,384	25,348	5.74

Virginia Electric and Power Company

Year of Report
December 31, 1982

SALES OF ELECTRICITY BY RATE SCHEDULE

Notes to Pages 304 and 304A

A. Duplicate customers included in other rate schedules.

Estimated revenues resulting from fuel clause, fuel differential and prior year uncollected fuel expense.

FUEL REVENUES 1982

Account 440.0

Rate - 1 -	$18,653,089
2 -	44,199,539
3 -	295,387
17 -	9,209
26 -	101,646
70 -	238,767
72 -	956,134
74 -	5,123
75 -	2,782
76 -	23,522
77 -	11,278
84 -	54,825
85 -	35,853
86 -	198,181
87 -	121,409
Unbilled -	(933,000)
Subtotal -	$63,973,744

Account 442.1

Rate - 5 -	$20,907,610
6 -	26,725,362
7 -	71,276
8 -	177,811
9 -	507,700
26 -	323,258
78 -	2,340
79 -	1,482
Unbilled -	(387,000)
Subtotal -	$48,329,839

Account 442.2

Rate - 5 -	$ 1,194,052
6 -	30,979,323
8 -	10
10 -	(155,097)
26 -	13,294
Unbilled -	(249,000)
Subtotal -	$31,782,582

Account 444.1

$566,836

Account 444.2

$99,349

Account 445.0

NASA -	$ 1,072,217
MS -	(629,745)
OTHER -	11,749,499
Unbilled -	(53,000)
Subtotal -	$12,138,971

TOTAL - $156,891,321

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

SALES FOR RESALE (Account 447)

1. Report sales during the year to other electric utilities and to cities or other public authorities for distribution to ultimate consumers.

2. Provide in column (a) subheadings and classify sales as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Municipalities, (4) Cooperatives, and (5) Other Public Authorities. For *each sale* designate statistical classification in column (b) using the following codes: FP, firm power supplying total system requirements of customer or total requirements at a specific point of delivery; FP(C), firm power supplying total system requirements of customer or total requirements at a specific point of delivery with credit allowed customer for available standby; FP(P), firm power supplementing customer's own generation or other purchases; DP, dump power; O, other. Describe in a footnote the nature of any sales classified as Other Power. Place an "x" in column (c) if sale involves export across a state line. Group together sales coded "x" in column (c) by state (or county) of origin identified in column (e), providing a subtotal for each state (or county) of delivery in columns (l) and (p).

Line No.	Sales To (a)	Statistical Classification (b)	Export Across State Lines (c) (a)	FERC Rate Schedule No. (d)	Point of Delivery (State or county) (e)	Substation Ownership (If applicable) (f) (h)	MW or MVa of Demand (Specify which) (b): Contract Demand (g)	Average Monthly Maximum Demand (h)	Annual Maximum Demand (i)
1	Municipalities (d)(i)								
2	Town of Blackstone	FP		(e)	Blackstone, Virginia			5,467	6,342
3	Town of Culpeper	FP(P)*		(e)	Culpeper, Virginia	RS	1,000	3,015	3,360
4	Town of Elkton	FP		(e)	Elkton, Virginia	RS		2,595	3,576
5	City of Franklin #1	FP		(e)	Franklin, Virginia			9,172	12,742
6	City of Franklin #2	FP		(e)	Franklin, Virginia	RS		5,614	7,198
7	City of Harrisonburg	FP		(e)	Harrisonburg, Virginia	RS		41,006	51,036
8	Town of Iron Gate	FP		(e)	Iron Gate, Virginia	RS		373	534
9	City of Manassas #1	FP(P)*		(e)	Manassas, Virginia	RS	10,000	8,804	9,738
10	City of Manassas #2	FP(P)*		(e)	Manassas, Virginia		10,322	11,146	15,010
11	Town of Wakefield	FP		(e)	Wakefield, Virginia	RS		1,656	2,004
12	Town of Belhaven	FP		(e)	Belhaven, North Carolina	RS			
13	Town of Edenton	FP		(e)	Edenton, North Carolina			5,299	6,082
14	Elizabeth City	FP		(e)	Elizabeth City, N.C.	RS			
15	Town of Enfield	FP		(e)	Enfield, North Carolina	RS		3,576	4,162
16	City of Greenville	FP		(e)	Greenville, North Carolina	RS			
17	Town of Hamilton	FP		(e)	Hamilton, North Carolina	RS			
18	Town of Hertford	FP		(e)	Hertford, North Carolina	RS			
19	Town of Hobgood	FP		(e)	Hobgood, North Carolina				
20	Town of Robersonville	FP		(e)	Robersonville, N.C.	RS			
21	Town of Scotland Neck	FP		(e)	Scotland Neck, N.C.				
22	Town of Tarboro	FP		(e)	Tarboro, North Carolina	RS			
23	City of Washington	FP		(e)	Washington, North Carolina	RS			
24	City of Windsor	FP		(e)	Windsor, North Carolina	RS			
25									
26									
27									
28	R.E.A. Cooperatives								
29	B.A.R.C. Elec. Co-Op.	FP(P)		76	Bells Valley, Virginia (C)	RS			
30		FP(P)		76	Callaghan, Virginia (C)				
31		FP(P)		76	Fancy Hill, Virginia (C)				
32		FP(P)		76	Goshen, Virginia (C)	RS		[illegible],569	19,[illegible]
33		FP(P)		76	East Lexington, Va. (C)				
34		FP(P)		76	Buatleburg, Virginia (C)	RS			
35		FP		76	Cornwall, Virginia				
36									
37									
38	Central Va. Elec.								
39	Co-Op.	FP(P)		94	Curdsville, Virginia	CS			
40									
41									
42									
43	* Rate Schedule contains provision for breakdown,								
44	relay or parallel operation service.								

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

SALES FOR RESALE (Account 447) (Continued)

3. Report separately firm, dump, and other power sold to the same utility.
4. If delivery is made at a substation, indicate ownership in column (f), using the following codes: RS, respondent owned or leased; CS, customer owned or leased.
5. If a fixed number of megawatts of maximum demand is specified in the power contract as a basis of billings to the customer, enter this number in column (g). Base the number of megawatts of maximum demand entered in columns (h) and (i) on actual monthly readings. Furnish these figures whether or not they are used in the determination of demand charges. Show in column (j) type of demand reading (i.e., instantaneous, 15, 30, or 60 minutes integrated).
6. For column (l) enter the number of megawatt hours shown on the bills rendered to the purchasers.
7. Explain in a footnote any amounts entered in column (o), such as fuel or other adjustments.
8. If a contract covers several points of delivery and small amounts of electric energy are delivered at each point, such sales may be grouped.

Type of Demand Reading (j)	Voltage at Which Delivered (k)	Megawatt Hours (l)	REVENUE: Demand Charges (m)	REVENUE: Energy (n)	REVENUE: (f) Other Charges (o)	REVENUE: Total (p)	Line No.
							1
30 Min Int	12,500	27,187	$ 716,502	$ 604,873	$ (27,573)	$ 1,293,802	2
30 Min Int	12,500	16,988	294,179	384,459	(18,422)	660,216	3
30 Min Int	4,160	12,951	310,275	289,748	(11,428)	588,595	4
30 Min Int	13,200	49,172	1,127,944	1,106,527	(48,686)	2,185,785	5
30 Min Int	13,200	29,352	746,775	655,815	(31,709)	1,370,881	6
30 Min Int	69,000	246,932	4,995,086	5,477,588	(250,219)	10,222,455	7
30 Min Int	2,400	2,007	45,691	45,047	(1,960)	88,778	8
30 Min Int	12,500	50,716	1,070,430	1,147,015	(49,944)	2,167,501	9
30 Min Int	13,200	55,217	1,389,773	1,216,185	(46,408)	2,559,550	10
30 Min Int	4,160	9,056	201,933	203,352	(9,385)	395,900	11
	4,160						12
30 Min Int	12,500						13
	34,500						14
30 Min Int	4,160	20,437	478,153	457,783	(23,244)	912,692	15
	230,000						16
	4,160						17
	4,160						18
	12,500			(1)		(1)	19
	4,160 12,500						20
	12,500						21
	12,500						22
	115,000						23
	12,500	26,590	700,957	592,652	(30,150)	1,263,459	24
							25
							26
							27
							28
	12,500						29
	46,000						30
	12,500						31
30 Min Int	46,000	70,987	1,547,762	1,526,311	(98,221)	2,975,852(g)	32
	12,500						33
	12,500						34
	46,000						35
							36
							37
							38
	115,000						39
							40
							41
							42
							43
							44

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

SALES FOR RESALE (Account 447)

1. Report sales during the year to other electric utilities and to cities or other public authorities for distribution to ultimate consumers.

2. Provide in column (a) subheadings and classify sales as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Municipalities, (4) Cooperatives, and (5) Other Public Authorities. For *each sale* designate statistical classification in column (b) using the following codes: FP, firm power supplying total system requirements of customer or total requirements at a specific point of delivery; FP(C), firm power supplying total system requirements of customer or total requirements at a specific point of delivery with credit allowed customer for available standby; FP(P), firm power supplementing customer's own generation or other purchases; DP, dump power; O, other. Describe in a footnote the nature of any sales classified as Other Power. Place an "x" in column (c) if sale involves export across a state line. Group together sales coded "x" in column (c) by state (or county) of origin identified in column (e), providing a subtotal for each state (or county) of delivery in columns (l) and (p).

Line No.	Sales To (a)	Statistical Classification (b)	Export Across State Lines (a) (c)	FERC Rate Schedule No. (d)	Point of Delivery (State or county) (e)	Substation Ownership (If applicable) (h) (f)	MW or MVa of Demand (b) (Specify which) Contract Demand (g)	Average Monthly Maximum Demand (h)	Annual Maximum Demand (i)
1	Central Va. Elec.								
2	Co-Op. (Cont'd)	FP(P)		94	Midway, Virginia (C)	CS			
3		FP(P)		94	Appomattox, Virginia (C)				
4		FP(P)		94	Columbia, Virginia (C)				
5		FP(P)		94	Gladstone, Virginia (C)				
6		FP(P)		94	Mt. Rush, Virginia (C)	CS			
7		FP(P)		94	Kidds Store, Virginia (C)	CS			
8		FP(P)		94	Piney River, Virginia (C)	CS			
9		FP(P)		94	White Hall, Virginia (C)	RS			
10		FP(P)		94	Pamplin, Virginia (C)			41,459	59,613
11		FP(P)		94	Cash's Corner, Virginia (C)	CS			
12		FP(P)		94	Trice's Lake, Virginia (C)	CS			
13		FP(P)		94	Cartersville, Virginia (C)	CS			
14		FP(P)		94	Scotteville	CS			
15		FP(P)		94	Doubleday-Madison Run (C)	CS			
16		FP(P)		94	Schuyler, Virginia	CS			
17		FP(P)		94	Trevilians, Virginia	RS			
18	Community Electric	FP(P)		77	Black Creek, Virginia (C)				
19	Co-Op.	FP(P)		77	Capron, Virginia (C)	CS			
20		FP(P)		77	Holland, Virginia (C)	CS			
21		FP(P)		77	Pagan, Virginia (C)	RS		14,814	19,325
22		FP(P)		77	Windsor, Virginia (C)	CS			
23		FP(P)		77	Hancsom, Virginia (C)	CS			
24		FP(P)		77	Courtland, Virginia (C)				
25		FP(P)		77	Lummis, Virginia (C)				
26		FP(P)		77	Sadlers, Virginia (C)				
27		FP(P)		77	Harrells, Virginia (C)				
28	Craig-Botetourt	FP(P)		78	Eagle Rock, Virginia (C)	CS			
29	Elec. Co-Op.	FP(P)		78	New Castle, Virginia (C)	CS			
30		FP(P)		78	Sweet Chalybeate, Va. (C)	CS		6,186	9,078
31		FP(P)		78	Potts Creek, Virginia (C)				
32		FP(P)		78	Stone Coal Gap, Va. (C)	CS			
33	Mecklenburg, Elec.	FP(P)		79	Beecnwood, Virginia (C)	CS			
34	Co-Op.	FP(P)		79	Black Branch, Virginia (C)	CS			
35		FP(P)		79	Climax, Virginia (C)	CS			
36		FP(P)		79	Crystal Hill, Virginia (C)	CS		37,782	45,671
37		FP(P)		79	Emporia, Virginia (C)	CS			
38		FP(P)		79	Gasburg, Virginia (C)	CS			
39		FP(P)		79	Gretna, Virginia (C)	CS			
40		FP(P)		79	Jones Store, Virginia	CS			
41		FP(P)		79	Mt. Airy, Virginia (C)	CS			
42		FP(P)		79	North View, Virginia (C)	CS			
43		FP(P)		79	Freeman, Virginia (C)	CS			
44		FP(P)		79	Grit, Virginia (C)	CS			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SALES FOR RESALE (Account 447) (Continued)

3. Report separately firm, dump, and other power sold to the same utility.
4. If delivery is made at a substation, indicate ownership in column (f), using the following codes: RS, respondent owned or leased; CS, customer owned or leased.
5. If a fixed number of megawatts of maximum demand is specified in the power contract as a basis of billings to the customer, enter this number in column (g). Base the number of megawatts of maximum demand entered in columns (h) and (i) on actual monthly readings. Furnish these figures whether or not they are used in the determination of demand charges. Show in column (j) type of demand reading (i.e., instantaneous, 15, 30, or 60 minutes integrated).
6. For column (l) enter the number of megawatt hours shown on the bills rendered to the purchasers.
7. Explain in a footnote any amounts entered in column (o), such as fuel or other adjustments.
8. If a contract covers several points of delivery and small amounts of electric energy are delivered at each point, such sales may be grouped.

Type of Demand Reading (j)	Voltage at Which Delivered (k)	Megawatt Hours (l)	REVENUE: Demand Charges (m)	REVENUE: Energy (n)	REVENUE: Other Charges (o)	REVENUE: Total (p)	Line No.
							1
	115,000		$	$	$	$	2
	12,500						3
	12,500						4
	46,000						5
	34,500						6
	115,000						7
	46,000						8
	23,000						9
30 Min Int	23,000	218,223	5,032,956	4,700,957	(193,073)	9,540,840	10
	115,000						11
	115,000						12
	34,500						13
	46,000						14
	115,000						15
	46,000						16
	34,500						17
	13,200						18
	34,500						19
	115,000						20
	13,200	71,298	1,889,935	1,513,334	(65,993)	3,337,276	21
	34,500						22
	115,000						23
	13,200						24
	12,500						25
	13,200						26
	12,500						27
	46,000						28
	34,500						29
	46,000	33,279	793,159	724,489	(31,975)	1,485,673	30
	12,500						31
	34,500						32
	115,000						33
	69,000						34
	69,000						35
	115,000	195,815	4,505,978	3,869,099	(203,328)	8,171,749	36
	115,000						37
	69,000						38
	69,000						39
	69,000						40
	69,000						41
	69,000						42
	115,000						43
	115,000						44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SALES FOR RESALE (Account 447)

1. Report sales during the year to other electric utilities and to cities or other public authorities for distribution to ultimate consumers.

2. Provide in column (a) subheadings and classify sales as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Municipalities, (4) Cooperatives, and (5) Other Public Authorities. For *each sale* designate statistical classification in column (b) using the following codes: FP, firm power supplying total system requirements of customer or total requirements at a specific point of delivery; FP(C), firm power supplying total system requirements of customer or total requirements at a specific point of delivery with credit allowed customer for available standby; FP(P), firm power supplementing customer's own generation or other purchases; DP, dump power; O, other. Describe in a footnote the nature of any sales classified as Other Power. Place an "x" in column (c) if sale involves export across a state line. Group together sales coded "x" in column (c) by state (or county) of origin identified in column (e), providing a subtotal for each state (or county) of delivery in columns (i) and (p).

Line No.	Sales To (a)	Statistical Classification (b)	Export Across State Lines (c)	FERC Rate Schedule No. (d)	Point of Delivery (State or county) (e)	Substation Ownership (If applicable) (f)	Contract Demand (g)	Average Monthly Maximum Demand (h)	Annual Maximum Demand (i)
							MW or MVa of Demand (Specify which)		
1	Mecklenburg Elec.	FP(P)		79	Hickory Grove, Virginia (C)	CS			
2	Co-Op. (Cont'd)	FP(P)		79	Brink, Virginia (C)	CS			
3		FP(P)		79	Clarksville, Virginia (C)	CS			
4		FP(P)		79	Omega, Virginia (C)	CS			
5		FP(P)		79	Boydton, Virginia (C)	CS			
6		FP(P)		79	Barnes Junction	CS			
7		FP(P)		79	Shockhoe, Virginia (C)	CS			
8	Northern Neck Elec.	FP(P)		80	Cross Hill, Virginia (C)				
9	Co-Op.	FP(P)		80	Folly, Virginia (C)				
10		FP(P)		80	Garner, Virginia (C)	RS		[illegible],430	23,[illegible]91
11		FP(P)		80	Oak Grove, Virginia (C)	CS			
12		FP(P)		80	Office Hall, Virginia (C)	RS			
13		FP(P)		80	Passapatanzy, Virginia (C)	RS			
14		FP(P)		80	Sanders, Virginia (C)	RS			
15	Prince George Elec.	FP(P)		82	Disputanta, Virginia (C)				
16	Co-Op.	FP(P)		82	Prince George, Virginia (C)				
17		FP(P)		82	Wakefield, Virginia (C)				
18		FP(P)		82	Waverly, Virginia (C)			11,676	18,631
19		FP(P)		82	Wilkerson's Corner, Va. (C)	RS			
20		FP(P)		82	Beechland, Virginia (C)	CS			
21		FP(P)		82	Spring Grove, Virginia (C)	RS			
22		FP(P)		82	Bacon's Castle, Virginia (C)	RS			
23		FP(P)		82	Booker, Virginia				
24		FP(P)		82	Rowanta, Virginia	RS			
25		FP(P)		82	Garysville, Virginia	RS			
26	Prince William	FP		83	Bethel, Virginia	CS		[illegible],510	9,[illegible]82
27	Elec. Co-Op.	FP		83	Broad Run, Virginia	CS		[illegible],003	4,026
28		FP		83	Gainsville, Virginia	RS		5[illegible],129	62,456
29		FP		83	Harrison, Virginia			[illegible],129	[illegible]2,[illegible]56
30		FP		83	Wellington, Virginia	RS		[illegible],260	9,088
31		FP		83	Johnson, Virginia	RS		[illegible],937	6,134
32		FP		83	Middleton, Virginia	RS		[illegible],252	[illegible],720
33		FP		83	Minnieville, Virginia	RS		[illegible],399	10,936
34		FP		83	Moore, Virginia	RS		[illegible],821	9,312
35		FP		83	Catharpin, Virginia	RS		[illegible],032	8,17[illegible]
36		FP		83	Country Club, Virginia	CS		[illegible],108	15,196
37		FP		83	Smoketown, Virginia	RS		[illegible],884	3,284
38		FP(P)		83	Heflin, Virginia (C)	RS			
39		FP(P)		83	Sowego, Virginia (C)	CS		11,444	21,574
40		FP(P)		83	Independent Hill, Va. (C)	CS			
41		FP		83	Lindendale, Virginia	CS		[illegible],546	11,865
42	Shenandoah Valley	FP(P)		84	Brands, Virginia (C)	CS			
43	Elec. Co-Op.	FP(P)		84	Cold Springs, Virginia (C)	CS			
44		FP(P)		84	Timberville, Virginia (C)	CS			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SALES FOR RESALE (Account 447) (Continued)

3. Report separately firm, dump, and other power sold to the same utility.
4. If delivery is made at a substation, indicate ownership in column (f), using the following codes: RS, respondent owned or leased; CS, customer owned or leased.
5. If a fixed number of megawatts of maximum demand is specified in the power contract as a basis of billings to the customer, enter this number in column (g). Base the number of megawatts of maximum demand entered in columns (h) and (i) on actual monthly readings. Furnish these figures whether or not they are used in the determination of demand charges. Show in column (j) type of demand reading (i.e., instantaneous, 15, 30, or 60 minutes integrated).
6. For column (l) enter the number of megawatt hours shown on the bills rendered to the purchasers.
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Type of Demand Reading (j)	Voltage at Which Delivered (k)	Megawatt Hours (l)	REVENUE: Demand Charges (m)	REVENUE: Energy (n)	REVENUE: Other Charges (o)	REVENUE: Total (p)	Line No.
	115,000		$	$	$	$	1
	115,000						2
	115,000						3
	115,000						4
	115,000						5
	115,000						6
	115,000						7
	12,500						8
	34,500						9
	34,500	89,998	2,238,278	1,893,062	(83,340)	4,048,000	10
	34,500						11
	12,500						12
	12,500						13
	34,500						14
	13,200						15
	13,200						16
	13,200						17
	13,200	64,188	1,769,725	1,389,340	(58,343)	3,100,722	18
	13,200						19
	34,500						20
	13,200						21
	12,500						22
	13,200						23
	13,200						24
	13,200						25
30 Min Int	115,000	38,620	877,006	710,351	(36,746)	1,550,611	26
30 Min Int	34,500	15,182	386,501	331,305	(13,770)	704,036	27
30 Min Int	69,000	132,703	2,938,338	2,696,005	(132,286)	5,502,057	28
30 Min Int	69,000	132,702	2,938,337	2,696,006	(106,632)	5,527,711	29
30 Min Int	115,000	32,788	986,877	722,614	(37,160)	1,672,331	30
30 Min Int	115,000	22,086	585,158	462,549	(18,595)	1,029,112	31
30 Min Int	12,500	5,062	162,471	114,816	(3,960)	273,327	32
30 Min Int	13,200	40,111	1,039,966	779,005	(37,084)	1,781,887	33
30 Min Int	13,200	32,216	876,047	696,289	(28,394)	1,543,942	34
30 Min Int	115,000	28,879	707,356	617,776	(23,401)	1,301,731	35
	115,000	38,564	1,061,028	844,778	(31,434)	1,874,372	36
	115,000	14,997	344,995	325,052	(15,158)	654,889	37
	13,200						38
	115,000	74,271	1,866,295	1,595,301	(59,518)	3,400,078	39
	115,000						40
	115,000	35,473	910,830	769,103	(25,825)	1,654,108	41
	115,000						42
	23,000						43
	115,000						44

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

SALES FOR RESALE (Account 447)

1. Report sales during the year to other electric utilities and to cities or other public authorities for distribution to ultimate consumers.

2. Provide in column (a) subheadings and classify sales as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Municipalities, (4) Cooperatives, and (5) Other Public Authorities. For *each sale* designate statistical classification in column (b) using the following codes: FP, firm power supplying total system requirements of customer or total requirements at a specific point of delivery; FP(C), firm power supplying total system requirements of customer or total requirements at a specific point of delivery with credit allowed customer for available standby; FP(P), firm power supplementing customer's own generation or other purchases; DP, dump power; O, other. Describe in a footnote the nature of any sales classified as Other Power. Place an "x" in column (c) if sale involves export across a state line. Group together sales coded "x" in column (c) by state (or county) of origin identified in column (e), providing a subtotal for each state (or county) of delivery in columns (l) and (p).

Line No.	Sales To (a)	Statistical Classification (b)	Export Across State Lines (a) (c)	FERC Rate Schedule No. (d)	Point of Delivery (State or county) (e)	(h) Substation Ownership (If applicable) (f)	MW or MVa of Demand (Specify which) (b) Contract Demand (g)	Average Monthly Maximum Demand (h)	Annual Maximum Demand (i)
1	Shenandoah Valley	FP(P)		84	Crimora, Virginia (C)				
2	Elec. Co-op. (Cont'd)	FP(P)		84	Dayton, Virginia (C)	CS			
3		FP(P)		84	Elkton, Virginia (C)			37,560	51,529
4		FP(P)		84	Gardner Springs, Virginia (C)				
5		FP(P)		84	Mt. Jackson, Virginia (C)				
6		FP(P)		84	Sherando, Virginia (C)	CS			
7		FP(P)		84	North River, Virginia (C)	CS			
8		FP		84	Columbia Furnance, Virginia	RS		1,430	[illegible]
9		FP		84	Woodstock, Virginia	CS		1,626	[illegible]
10		FP(P)		84	Trimbles Mill, Virginia (C)	CS			
11	Southside Elec.	FP(P)		85	Altavista, Virginia (C)				
12	Co-op.	FP(P)		85	Amelia, Virginia (C)	CS			
13		FP(P)		85	Fort Pickett, Virginia (C)	CS			
14		FP(P)		85	Center Star, Virginia (C)				
15		FP(P)		85	Cherry Hill, Virginia (C)				
16		FP(P)		85	Danieltown, Virginia (C)	CS			
17		FP(P)		85	Drakes Branch, Virginia (C)				
18		FP(P)		85	Evergreen, Virginia (C)	CS			
19		FP(P)		85	Evington, Virginia (C)	CS			
20		FP(P)		85	Gary, Virginia (C)	CS			
21		FP(P)		85	Gladys, Virginia (C)	CS		61,965	81,106
22		FP(P)		85	Hancock, Virginia (C)	CS			
23		FP(P)		85	Hooper, Virginia (C)	CS			
24		FP(P)		85	Lone Gum, Virginia (C)	CS			
25		FP(P)		85	Madisonville, Virginia (C)	CS			
26		FP(P)		85	Moran, Virginia (C)	CS			
27		FP(P)		85	Nutbush, Virginia (C)	CS			
28		FP(P)		85	Perth, Virginia				
29		FP(P)		85	Pointon, Virginia (C)				
30		FP(P)		85	Powhatan, Virginia (C)				
31		FP(P)		85	Reams, Virginia (C)				
32		FP(P)		85	Red House, Virginia (C)	CS			
33		FP(P)		85	Stoddert, Virginia (C)				
34		FP(P)		85	Whitehouse, Virginia (C)				
35		FP(P)		85	Martins, Virginia (C)	CS			
36		FP(P)		85	Gills, Virginia (C)				
37	Tri-County Elec.	FP		86	Arcola, Virginia	CS		1,691	2,156
38	Co-op.	FP		86	Club Run, Virginia	RS		3,675	5,044
39		FP		86	Herndon, Virginia			935	1,018
40		FP		86	Hillsboro, Virginia			2,459	3,582
41		FP		86	Leesburg, Virginia	CS		1,766	2,761
42		FP		86	Mt. Weather, Virginia			2,188	2,512
43		FP		86	Sycoline, Virginia	RS		2,158	3,421
44	Rappahanock Elec. Co-op.	FP(P)		101	Cuckoo, Virginia (C)	RS			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SALES FOR RESALE (Account 447) (Continued)

3. Report separately firm, dump, and other power sold to the same utility.

4. If delivery is made at a substation, indicate ownership in column (f), using the following codes: RS, respondent owned or leased; CS, customer owned or leased.

5. If a fixed number of megawatts of maximum demand is specified in the power contract as a basis of billings to the customer, enter this number in column (g). Base the number of megawatts of maximum demand entered in columns (h) and (i) on actual monthly readings. Furnish these figures whether or not they are used in the determination of demand charges. Show in column (j) type of demand reading (i.e., instantaneous, 15, 30, or 60 minutes integrated).

6. For column (l) enter the number of megawatt hours shown on the bills rendered to the purchasers.

7. Explain in a footnote any amounts entered in column (o), such as fuel or other adjustments.

8. If a contract covers several points of delivery and small amounts of electric energy are delivered at each point, such sales may be grouped.

Type of Demand Reading (j)	Voltage at Which Delivered (k)	Megawatt Hours (l)	REVENUE: Demand Charges (m)	Energy (n)	Other Charges (o)	Total (p)	Line No.
	23,000		$	$	$	$	1
	115,000						2
	34,500	226,190	4,540,781	4,829,792	(216,222)	9,154,351	3
	23,000						4
	34,500						5
	115,000						6
	115,000						7
30 Min Int	23,000	8,080	185,382	176,263	(7,778)	353,867	8
30 Min Int	34,500	8,912	211,625	194,986	(8,508)	398,103	9
	115,000						10
	12,500						11
	34,500						12
	115,000						13
	34,500						14
	34,500						15
	69,000						16
	12,500						17
	34,500						18
	115,000						19
	115,000						20
	69,000	306,872	7,693,707	6,543,948	(294,755)	13,942,900	21
	115,000						22
	115,000						23
	69,000						24
	34,500						25
	115,000						26
	115,000						27
	12,500						28
	34,500						29
	34,500						30
	34,500						31
	115,000						32
	34,500						33
	12,500						34
	115,000						35
	34,500						36
30 Min Int	115,000	8,556	202,776	184,565	(7,678)	379,663	37
30 Min Int	13,200	16,033	470,630	301,979	(15,101)	757,508	38
30 Min Int	34,500	2,684	123,289	63,271	(2,815)	183,745	39
30 Min Int	34,500	12,367	315,576	271,753	(10,513)	576,816	40
30 Min Int	34,500	8,622	225,527	190,222	(6,307)	409,442	41
30 Min Int	34,500	14,764	297,854	317,462	(15,836)	599,480	42
30 Min Int	12,500	10,155	277,075	226,085	(8,197)	494,963	43
	12,500						44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SALES FOR RESALE (Account 447)

1. Report sales during the year to other electric utilities and to cities or other public authorities for distribution to ultimate consumers.

2. Provide in column (a) subheadings and classify sales as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Municipalities, (4) Cooperatives, and (5) Other Public Authorities. For *each sale* designate statistical classification in column (b) using the following codes: FP, firm power supplying total system requirements of customer or total requirements at a specific point of delivery; FP(C), firm power supplying total system requirements of customer or total requirements at a specific point of delivery with credit allowed customer for available standby; FP(P), firm power supplementing customer's own generation or other purchases; DP, dump power; O, other. Describe in a footnote the nature of any sales classified as Other Power. Place an "x" in column (c) if sale involves export across a state line. Group together sales coded "x" in column (c) by state (or county) of origin identified in column (e), providing a subtotal for each state (or county) of delivery in columns (l) and (p).

Line No.	Sales To (a)	Statistical Classification (b)	Export Across State Lines (a) (c)	FERC Rate Schedule No. (d)	Point of Delivery (State or county) (e)	(h) Substation Ownership (If applicable) (f)	MW or MVa of Demand (Specify which) (b) Contract Demand (g)	Average Monthly Maximum Demand (h)	Annual Maximum Demand (i)
1	Rappahanock Elec.	FP(P)		101	Rixley, Virginia (C)	RS			
2	Co-op. (Cont'd)	FP(P)		101	Hustle, Virginia (C)	RS			
3		FP(P)		101	Locust Grove, Virginia (C)	CS			
4		FP(P)		101	Millers Tavern, Virginia (C)	CS			
5		FP(P)		101	N. Doswell, Virginia (C)	RS			
6		FP(P)		101	Paytes, Virginia (C)				
7		FP(P)		101	St. Johns Church, Virginia (C)	CS			
8		FP(P)		101	Unionville, Virginia (C)	RS			
9		FP(P)		101	Wilderness, Virginia (C)	RS			
10		FP(P)		101	Woodpecker, Virginia (C)	CS			
11		FP(P)		101	Orchid, Virginia (C)	RS		147,439	196,971
12		FP(P)		101	Kings Dominion, Virginia (C)	RS			
13		FP(P)		101	Slabtown, Virginia (C)	RS			
14		FP(P)		101	White Shop, Virginia (C)				
15		FP(P)		101	Deerfield, Virginia (C)				
16		FP(P)		101	Greenwood, Virginia				
17		FP(P)		101	Bear Island, Virginia	CS			
18		FP(P)		101	Culpeper No. 1, Virginia (C)	RS			
19		FP(P)		101	Culpeper No. 2, Virginia (C)				
20		FP(P)		101	Orange, Virginia (C)				
21		FP(P)		101	Warrenton, Virginia (C)	CS			
22		FP(P)		101	Oak Shade, Virginia (C)				
23		FP(P)		101	Decapolis, Virginia (C)	CS			
24		FP(P)		101	Dunnes, Virginia (C)				
25		FP(P)		101	Gold Mine, Virginia (C)	RS			
26		FP(P)		101	Brandy, Virginia (C)	CS			
27		FP(P)		101	Orleans, Virginia (C)				
28	Albermarle Elec.	FP(P)		88	Burgess, North Carolina (C)	CS			
29	Memb. Corp.	FP(P)		88	Camden, North Carolina (C)	CS			
30		FP(P)		88	Edenton, North Carolina (C)	CS		1,638	15,088
31		FP(P)		88	Elizabeth City, North Carolina	CS			
32		FP(P)		88	Morgans Corner, North Carolina	RS			
33		FP(P)		88	Winfall, North Carolina (C)	CS			
34		FP(P)		88	South Mills, N. C. (C)				
35		FP(P)		88	Weeksville, North Carolina				
36		FP(P)		88	Cisco, North Carolina				
37	Edgecombe-Martin	FP(P)		90	Benson, North Carolina (C)	RS			
38	Co. Elec. Memb.	FP(P)		90	Fountain, North Carolina (C)				
39	Corp.	FP(P)		90	Hamilton, North Carolina (C)	CS		19,201	26,292
40		FP(P)		90	Legett Cross Roads, N.C. (C)	RS			
41		FP(P)		90	Mayo-Dunbar, N. C. (C)	CS			
42		FP(P)		90	Parmele, North Carolina (C)	CS			
43		FP(P)		90	Tarboro, North Carolina (C)	CS			
44		FP(P)		90	Wiggins Cross Roads, N.C. (C)	RS			

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

SALES FOR RESALE (Account 447) (Continued)

3. Report separately firm, dump, and other power sold to the same utility.

4. If delivery is made at a substation, indicate ownership in column (f), using the following codes: RS, respondent owned or leased; CS, customer owned or leased.

5. If a fixed number of megawatts of maximum demand is specified in the power contract as a basis of billings to the customer, enter this number in column (g). Base the number of megawatts of maximum demand entered in columns (h) and (i) on actual monthly readings. Furnish these figures whether or not they are used in the determination of demand charges. Show in column (j) type of demand reading (i.e., instantaneous, 15, 30, or 60 minutes integrated).

6. For column (l) enter the number of megawatt hours shown on the bills rendered to the purchasers.

7. Explain in a footnote any amounts entered in column (o), such as fuel or other adjustments.

8. If a contract covers several points of delivery and small amounts of electric energy are delivered at each point, such sales may be grouped.

Type of Demand Reading (j)	Voltage at Which Delivered (k)	Megawatt Hours (l)	REVENUE: Demand Charges (m)	REVENUE: Energy (n)	REVENUE: (f) Other Charges (o)	REVENUE: Total (p)	Line No.
	12,500		$	$	$	$	1
	12,500						2
	115,000						3
	34,500						4
	12,500						5
	34,500						6
	115,000						7
	13,200						8
	12,500						9
	115,000						10
	12,500	1,041,903	19,054,137	23,100,175	(840,931)	41,313,381	11
	115,000						12
	12,500						13
	13,200						14
	34,500						15
	115,000						16
	230,000						17
	12,500						18
	12,500						19
	12,500						20
	34,500						21
	34,500						22
	34,500						23
	34,500						24
	12,500						25
	115,000						26
	34,500						27
	34,500						28
	13,200						29
	34,500	56,779	1,559,126	1,199,649	(90,324)	2,668,451	30
	34,500						31
	13,200						32
	34,500						33
	13,200						34
	13,200						35
	12,500						36
	12,500						37
	12,500						38
	34,500	91,760	2,511,419	1,920,989	(152,665)	4,279,743	39
	12,500						40
	115,000						41
	115,000						42
	115,000						43
	12,500						44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SALES FOR RESALE (Account 447)

1. Report sales during the year to other electric utilities and to cities or other public authorities for distribution to ultimate consumers.

2. Provide in column (a) subheadings and classify sales as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Municipalities, (4) Cooperatives, and (5) Other Public Authorities. For *each sale* designate statistical classification in column (b) using the following codes: FP, firm power supplying total system requirements of customer or total requirements at a specific point of delivery; FP(C), firm power supplying total system requirements of customer or total requirements at a specific point of delivery with credit allowed customer for available standby; FP(P), firm power supplementing customer's own generation or other purchases; DP, dump power; O, other. Describe in a footnote the nature of any sales classified as Other Power. Place an "x" in column (c) if sale involves export across a state line. Group together sales coded "x" in column (c) by state (or county) of origin identified in column (e), providing a subtotal for each state (or county) of delivery in columns (l) and (p).

Line No.	Sales To (a)	Statistical Classification (b)	Export Across State Lines (a) (c)	FERC Rate Schedule No. (d)	Point of Delivery (State or county) (e)	Substation Ownership (If applicable) (c) (f)	MW or MVa of Demand (Specify which) (b) — Contract Demand (g)	Average Monthly Maximum Demand (h)	Annual Maximum Demand (i)
1	Edgecombe-Martin Co.								
2	Elec. Memb. Corp.	FP(P)		90	Wilson-Robersonville, N.C. (C)	RS			
3	(Continued)	FP(P)		90	Conetoe, North Carolina (C)	CS			
4	Halifax Elec. Memb.	FP(P)		91	Eaton's Ferry, N. C. (C)	RS			
5	Corp.	FP(P)		91	Enfield, North Carolina (C)	CS			
6		FP(P)		91	Dawson's, North Carolina (C)			8,30[illegible]	[illegible]
7		FP(P)		91	Medoc, North Carolina (C)	CS			
8		FP(P)		91	Scotland Neck, N. C.				
9		FP(P)		91	[illegible] Head, North Carolina	RS			
10	Roanoke Elec. Memb.	FP(P)		92	Aulander, North Carolina (C)	CS			
11	Corp.	FP(P)		92	Conway, North Carolina (C)	CS			
12		FP(P)		92	Eason's Cross Roads, N.C. (C)				
13		FP(P)		92	Gum Fork, North Carolina (C)	CS		19,331	21,407
14		FP(P)		92	Halifax, North Carolina (C)	CS			
15		FP(P)		92	Merry Hill, N. C. (C)	CS			
16		FP(P)		92	Windsor, North Carolina (C)	CS			
17		FP(P)		92	Woodville, North Carolina	CS			
18		FP(P)		92	Jackson, North Carolina (C)	CS			
19		FP(P)		92	Reduce, North Carolina (C)	CS			
20	Tideland Elec. Memb.	FP(P)		93	Five Point, N. C. (C)				
21	Corp.	FP(P)		93	Pantego, North Carolina (C)	CS		[illegible]	19,479
22		FP(P)		93	Plymouth, North Carolina (C)	CS			
23		FP(P)		93	Fairfield, North Carolina (C)				
24	Cape Hatteras Elec.	FP		89	Lighthouse, North Carolina			9,35[illegible]	13,072
25	Memb. Corp								
26									
27	Reserve:								
28	Unbilled								
29	Billed								
30	Unbilled								
31									
32									
33									

34 Notes to pages 310 - 310 E and 311 - 311 E

35 (a) Certain electric energy sold to the above utilities in the States of Virginia and
36 North Carolina may have been transmitted by the respondent across said State line.
37 (b) As mutually agreed to by the parties but not less than 300 kW.
38 (c) Customer of respondent only to the extent that demand exceeds contract demand agreed
39 to by Southeastern Power Administration and the customer. (Columns (h), (i), (l), (m),
40 (n), (o) and (p) not separated by delivery points.)
41 (d) Amounts shown on columns (h) and (i) represent kW of demand for the municipalities.
42 (e) F.E.R.C. Electric Tariff, First Revised Volume No. 1 effective 1/28/77 as modified.
43 (also see Note (i) below).
44

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

SALES FOR RESALE (Account 447) (Continued)

3. Report separately firm, dump, and other power sold to the same utility.
4. If delivery is made at a substation, indicate ownership in column (f), using the following codes: RS, respondent owned or leased; CS, customer owned or leased.
5. If a fixed number of megawatts of maximum demand is specified in the power contract as a basis of billings to the customer, enter this number in column (g). Base the number of megawatts of maximum demand entered in columns (h) and (i) on actual monthly readings. Furnish these figures whether or not they are used in the determination of demand charges. Show in column (j) type of demand reading (i.e., instantaneous, 15, 30, or 60 minutes integrated).
6. For column (l) enter the number of megawatt hours shown on the bills rendered to the purchasers.
7. Explain in a footnote any amounts entered in column (o), such as fuel or other adjustments.
8. If a contract covers several points of delivery and small amounts of electric energy are delivered at each point, such sales may be grouped.

Type of Demand Reading (j)	Voltage at Which Delivered (k)	Megawatt Hours (l)	REVENUE: Demand Charges (m)	Energy (n)	(f) Other Charges (o)	Total (p)	Line No.
							1
	13,200		$	$	$	$	2
	115,000						3
	12,500						4
	115,000						5
	12,500	44,194	1,104,966	927,169	(74,646)	1,957,489	6
	34,500						7
	12,500						8
	12,500						9
	34,500						10
	34,500						11
	12,500						12
	34,500	98,196	2,574,755	2,063,484	(159,897)	4,478,342	13
	115,000						14
	34,500						15
	34,500						16
	34,500						17
	115,000						18
	34,500						19
	34,500						20
	34,500	84,187	2,098,984	1,794,616	(135,610)	3,757,990	21
	34,500						22
	34,500						23
30 Min Int	34,500	42,060	1,118,245	897,751	(74,594)	1,941,402	24
							25
							26
							27
				19,661		19,661	28
		692,566		36,051,337		36,051,337	29
		2,732		399,000		399,000	30
				34,950(g)		34,950(g)	31
							32
TOTAL		4,712,059	90,100,550	122,867,692	(3,975,741)	208,992,501(g)	33
							34
							35
							36
							37

(f) Column (o) represents fuel charge, RKVA and facilities charge. 38
(g) Bath County Pumped Storage Project. 39
(h) Substation ownership shown in Column (f) is based upon whether or not a substation 40
exists to supply the delivery voltage. 41
(i) Filed rate applicable to municipalities is an interim rate, subject to refund. 42
43
44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric & Power Co	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnotes.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	$ 10,102,729	$ 7,139,353
5	(501) Fuel	418,861,433	450,078,736
6	(502) Steam Expenses	7,061,814	5,296,555
7	(503) Steam from Other Sources	-	-
8	(504) Steam Transferred–Cr.	-	-
9	(505) Electric Expenses	4,256,225	3,951,321
10	(506) Miscellaneous Steam Power Expenses	16,883,582	13,180,576
11	(507) Rents	374,580	272,662
12	TOTAL Operation *(Enter Total of lines 4 thru 11)*	457,540,363	509,919,263
13	Maintenance		
14	(510) Maintenance Supervision and Engineering	6,954,38[illegible]	5,571,908
15	(511) Maintenance of Structures	[illegible]	[illegible]
16	(512) Maintenance of Boiler Plant	41,512,982	35,737,166
17	(513) Maintenance of Electric Plant	16,386,011	14,732,987
18	(514) Maintenance of Miscellaneous Steam Plant	11,805,147	8,739,838
19	TOTAL Maintenance *(Enter Total of lines 14 thru 18)*	79,573,460	56,660,543
20	TOTAL Power Production Expenses–Steam Power *(Enter Total of lines 12 and 19)*	537,113,823	576,579,746
21	B. Nuclear Power Generation		
22	Operation		
23	(517) Operation Supervision and Engineering	12,111,307	13,770,553
24	(518) Fuel	106,250,285	116,235,531
25	(519) Coolants and Water	2,172,345	2,498,093
26	(520) Steam Expenses	6,017,592	4,653,825
27	(521) Steam from Other Sources	40	476
28	(522) Steam Transferred–Cr.	986	2,170
29	(523) Electric Expenses	1,739,177	1,277,463
30	(524) Miscellaneous Nuclear Power Expenses	22,586,375	13,462,534
31	(525) Rents	463,437	140,171
32	TOTAL Operation *(Enter Total of lines 23 thru 31)*	151,341,547	152,040,836
33	Maintenance		
34	(528) Maintenance Supervision and Engineering	5,767,717	3,685,626
35	(529) Maintenance of Structures	2,561,207	1,755,761
36	(530) Maintenance of Reactor Plant Equipment	12,600,816	10,431,195
37	(531) Maintenance of Electric Plant	7,219,918	5,541,941
38	(532) Maintenance of Miscellaneous Nuclear Plant	3,340,198	2,820,390
39	TOTAL Maintenance *(Enter Total of lines 34 thru 38)*	31,489,856	24,234,913
40	TOTAL Power Production Expenses–Nuclear Power *(Enter Total of lines 32 and 39)*	182,831,403	176,275,749
41	C. Hydraulic Power Generation		
42	Operation		
43	(535) Operation Supervision and Engineering	347,786	279,641
44	(536) Water for Power	1,219,998	1,012,934
45	(537) Hydraulic Expenses	187,598	149,640
46	(538) Electric Expenses	221,846	200,780
47	(539) Miscellaneous Hydraulic Power Generation Expenses	109,972	129,292
48	(540) Rents	-	236
49	TOTAL Operation *(Enter Total of lines 43 thru 48)*	$ 2,087,200	$ 1,772,523

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric & Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
50	C. Hydraulic Power Generation (Continued)		
51	Maintenance		
52	(541) Maintenance Supervision and Engineering	$ 322,977	$ 254,549
53	(542) Maintenance of Structures	90,404	64,185
54	(543) Maintenance of Reservoirs, Dams, and Waterways	43,038	36,666
55	(544) Maintenance of Electric Plant	479,304	212,186
56	(545) Maintenance of Miscellaneous Hydraulic Plant	92,787	58,925
57	TOTAL Maintenance *(Enter Total of lines 52 thru 56)*	1,028,510	626,511
58	TOTAL Power Production Expenses—Hydraulic Power *(Enter Total of lines 49 and 57)*	3,115,710	2,399,034
59	D. Other Power Generation		
60	Operation		
61	(546) Operation Supervision and Engineering	306,656	205,638
62	(547) Fuel	4,235,519	17,893,028
63	(548) Generation Expenses	93,552	109,686
64	(549) Miscellaneous Other Power Generation Expenses	181,071	197,356
65	(550) Rents	5,350,912	5,451,259
66	TOTAL Operation *(Enter Total of lines 61 thru 65)*	10,167,710	23,856,967
67	Maintenance		
68	(551) Maintenance Supervision and Engineering	149,088	230,924
69	(552) Maintenance of Structures	136,703	168,422
70	(553) Maintenance of Generating and Electric Plant	1,895,575	2,025,597
71	(554) Maintenance of Miscellaneous Other Power Generation Plant	124,391	159,555
72	TOTAL Maintenance *(Enter Total of lines 68 thru 71)*	2,305,757	2,584,498
73	TOTAL Power Production Expenses—Other Power *(Enter Total of lines 66 and 72)*	12,473,467	26,441,465
74	E. Other Power Supply Expenses		
75	(555) Purchased Power	274,567,896	289,558,041
76	(556) System Control and Load Dispatching	698,651	571,939
77	(557) Other Expenses	13,466,753	(58,663,085)
78	TOTAL Other Power Supply Expenses *(Enter Total of lines 75 thru 77)*	288,733,300	231,466,895
79	TOTAL Power Production Expenses *(Enter Total of lines 20, 40, 58, 73, and 78)*	1,024,267,703	1,013,162,889
80	2. TRANSMISSION EXPENSES		
81	Operation		
82	(560) Operation Supervision and Engineering	1,997,811	1,530,148
83	(561) Load Dispatching	341,820	276,301
84	(562) Station Expenses	722,382	647,539
85	(563) Overhead Line Expenses	660,105	584,507
86	(564) Underground Line Expenses	-	-
87	(565) Transmission of Electricity by Others	-	-
88	(566) Miscellaneous Transmission Expenses	294,063	222,157
89	(567) Rents	260,460	285,637
90	TOTAL Operation *(Enter Total of lines 82 thru 89)*	4,276,641	3,546,289
91	Maintenance		
92	(568) Maintenance Supervision and Engineering	1,254,239	852,983
93	(569) Maintenance of Structures	38,451	34,262
94	(570) Maintenance of Station Equipment	3,289,506	2,889,422
95	(571) Maintenance of Overhead Lines	4,184,575	2,833,250
96	(572) Maintenance of Underground Lines	5,488	2,721
97	(573) Maintenance of Miscellaneous Transmission Plant	39,433	35,088
98	TOTAL Maintenance *(Enter Total of lines 92 thru 97)*	8,811,692	6,647,726
99	TOTAL Transmission Expenses *(Enter Total of lines 90 and 98)*	13,088,333	10,194,015
100	3. DISTRIBUTION EXPENSES		
101	Operation		
102	(580) Operation Supervision and Engineering	8,458,280	6,701,793
103	(581) Load Dispatching	-	-

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric & Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(582) Station Expenses	$ 2,475,152	$ 2,177,076
106	(583) Overhead Line Expenses	3,476,531	4,115,675
107	(584) Underground Line Expenses	1,834,835	1,245,432
108	(585) Street Lighting and Signal System Expenses	911,858	926,770
109	(586) Meter Expenses	5,408,074	4,787,472
110	(587) Customer Installations Expenses	2,150,368	1,509,601
111	(588) Miscellaneous Distribution Expenses	12,735,668	10,118,040
112	(589) Rents	729,336	517,907
113	TOTAL Operation *(Enter Total of lines 102 thru 112)*	38,180,102	32,099,766
114	Maintenance		
115	(590) Maintenance Supervision and Engineering	3,706,731	2,947,373
116	(591) Maintenance of Structures	82,870	48,305
117	(592) Maintenance of Station Equipment	4,850,009	3,519,803
118	(593) Maintenance of Overhead Lines	22,079,151	13,533,880
119	(594) Maintenance of Underground Lines	5,634,403	4,595,249
120	(595) Maintenance of Line Transformers	1,510,207	1,319,006
121	(596) Maintenance of Street Lighting and Signal Systems	1,779,391	1,659,129
122	(597) Maintenance of Meters	784,768	720,510
123	(598) Maintenance of Miscellaneous Distribution Plant	477,031	331,486
124	TOTAL Maintenance *(Enter Total of lines 115 thru 123)*	40,904,761	33,674,741
125	TOTAL Distribution Expenses *(Enter Total of lines 113 and 124)*	79,084,863	65,774,507
126	4. CUSTOMER ACCOUNTS EXPENSES		
127	Operation		
128	(901) Supervision	1,746,811	1,493,280
129	(902) Meter Reading Expenses	8,454,808	7,664,707
130	(903) Customer Records and Collection Expenses	19,505,751	16,411,004
131	(904) Uncollectible Accounts	4,224,068	4,554,970
132	(905) Miscellaneous Customer Accounts Expenses	-	-
133	TOTAL Customer Accounts Expenses *(Enter Total of lines 128 thru 132)*	33,931,438	30,123,961
134	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
135	Operation		
136	(907) Supervision	1,357,561	872,246
137	(908) Customer Assistance Expenses	2,523,845	1,692,084
138	(909) Informational and Instructional Expenses	418,799	26,114
139	(910) Miscellaneous Customer Service and Informational Expenses	169,401	144,064
140	TOTAL Cust. Service and Informational Exp. *(Enter Total of lines 136 thru 139)*	4,469,606	2,734,508
141	6. SALES EXPENSES		
142	Operation		
143	(911) Supervision	-	-
144	(912) Demonstrating and Selling Expenses	-	-
145	(913) Advertising Expenses	-	-
146	(916) Miscellaneous Sales Expenses	-	-
147	TOTAL Sales Expenses *(Enter Total of lines 143 thru 146)*	-	-
148	7. ADMINISTRATIVE AND GENERAL EXPENSES		
149	Operation		
150	(920) Administrative and General Salaries	29,409,300	22,572,970
151	(921) Office Supplies and Expenses	16,842,805	13,566,028
152	(922) Administrative Expenses Transferred—Cr.	(6,874,363)	(5,184,430)
153	(923) Outside Services Employed	2,939,783	2,682,629
154	(924) Property Insurance	10,361,255	6,880,322
155	(925) Injuries and Damages	5,385,981	5,423,177
156	(926) Employee Pensions and Benefits	21,861,928	20,795,645

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric & Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
157	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
158	(927) Franchise Requirements	$ 8,423	$ 500
159	(928) Regulatory Commission Expenses	3,005,279	3,752,209
160	(929) Duplicate Charges—Cr.	(1,955,739)	(1,503,564)
161	(930.1) General Advertising Expenses	1,238	211,585
162	(930.2) Miscellaneous General Expenses	17,136,741	16,734,929
163	(931) Rents	4,247,765	3,732,351
164	TOTAL Operation *(Enter Total of lines 150 thru 163)*	102,370,396	89,664,351
165	Maintenance		
166	(932) Maintenance of General Plant	2,474,799	1,846,563
167	TOTAL Administrative and General Expenses *(Enter Total of lines 164 thru 166)*	104,845,195	91,510,914
168	TOTAL Electric Operation and Maintenance Expenses *(Enter Total of lines 79, 99, 125, 133, 140, 147, and 167)*	1,259,687,138	1,213,500,794

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.
2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.
3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1.	Payroll Period Ended (Date) December 31, 1982	
2.	Total Regular Full-Time Employees	12,240
3.	Total Part-Time and Temporary Employees	181
4.	Total Employees	12,421
	Equivalent Employees From Joint Functions	1,755

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

PURCHASED POWER (Account 555)
(Except interchange power)

1. Report power purchased for resale during the year. Report on page 328 particulars (details) concerning interchange power transactions during the year; do not include such figures on this page.
2. Provide in column (a) subheadings and classify purchases as to: (1) Associated Utilities, (2) Nonassociated Utilities, (3) Associated Nonutilities, (4) Other Nonutilities, (5) Municipalities, (6) Cooperatives, and (7) Other Public Authorities. For each purchase designate statistical classification in column (b) using the following codes: FP, firm power; DP, dump or surplus power; O, other. Describe the nature of any purchases classified as Other Power. Enter an "x" in column (c) if purchase involves import across a state line.
3. Report separately firm, dump, and other power purchased

Line No.	Purchased From (a)	Statistical Classification (b)	Import Across State Lines (c)	FERC Rate Schedule No. of Seller (d)	Point of Receipt (e)	Substation Ownership (If applicable) (f)	MW or MVa of Demand (Specify which): Contract Demand (g)	Average Monthly Maximum Demand (h)	Annual Maximum Demand (i)
2	NONASSOCIATED								
3	UTILITIES								
4	Appalachian Power								
5	Company	FP	(a)	7	Cloverdale,		(b)	(b)	
6					Altavista, Bremo,				
7					Va. and Hinton,				
8					W. Va.				
11	OTHER PUBLIC								
12	AUTHORITIES								
13	Southeastern Power								
14	Administration	FP		100	Kerr Dam, Virginia	SS	NOT APPLICABLE		

(a) Certain energy may have been exchanged across state line.

(b) Limited term power was purchased in March 1982. The contract demand and maximum monthly demand for the month of March was 400 Mw. System unit power is contracted on a monthly basis. The contract demand and maximum monthly demand for each month are the same. January-December - 600 Mw.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

PURCHASED POWER (Account 555) (Continued)
(Except interchange power)

from the same company.

4. If receipt of power is at a substation, indicate ownership in column (f), using the following codes: RS, respondent owned or leased; SS, seller owned or leased.

5. If a fixed number of megawatts of maximum demand is specified in the power contract as a basis of billing, enter this number in column (g). Base the number of megawatts of maximum demand shown in columns (h) and (i) on actual monthly readings. Furnish those figures whether they are used or not in the determination of demand charges. Show in column (j) type of demand reading (i.e. instantaneous, 15, 30, or 60 minutes integrated).

6. For column (l) enter the number of megawatt hours purchased as shown by the power bills rendered to the purchases.

7. Explain in a footnote any amount entered in column (o), such as fuel or other adjustments.

Type of Demand Reading (j)	Voltage at Which Received (k)	Megawatt Hours (l)	Cost Of Energy: Demand Charges (m)	Energy Charges (n)	Other Charges (o)	Total (m+n+o) (p)	Line No.
							1
							2
							3
60 Min.	138,000	3,305,661	$48,018,585	$91,107,589		$139,126,174	4
	500,000						5
							6
							7
							8
							9
							10
							11
							12
							13
			1,491,935			1,491,935	14
							15
Total		3,305,661	$49,510,520	$91,107,589		$140,618,109	16
							17
							18
							19
							20
							21
							22
							23
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUMMARY OF INTERCHANGE ACCORDING TO COMPANIES AND POINTS OF INTERCHANGE

(Included in Account 555)

1. Report below all of the megawatt-hours received and delivered during the year. For receipts and deliveries under interchange power agreements, show the net charge or credit resulting therefrom.
2. Provide subheadings and classify interchanges as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Associated Nonutilities, (4) Other Nonutilities, (5) Municipalities, (6) Cooperatives, and (7) Other Public Authorities. For each interchange across a state line place an "x" in column (b).
3. Furnish particulars (details) of settlements for interchange power in a footnote or on a supplemental page; include the name of each company, the nature of the transaction, and the dollar amounts involved. If settlement for any transaction also includes credit or debit amounts other than for increment generation expenses, show such other component amounts separately, in addition to debit or credit for increment generation expenses, and give a brief explanation of the factors and principles under which such other component amounts were determined. If such settlement represents the net of debits and credits under an interconnection, power pooling, coordination, or other such arrangement, submit a copy of the annual summary of transactions and billings among the parties to the agreement. If the amount of settlement reported in this schedule for any transaction does not represent all of the charges and credits covered by the agreement, furnish in a footnote a description of the other debits and credits and state the amounts and accounts in which such other amounts are included for the year.

Line No.	Name of Company (a)	Interchanges Across State Lines (b)	FERC Rate Schedule Number (c)	Point of Interchange (d)	Voltage at Which Interchanged (e)	Megawatt Hours: Received (f)	Megawatt Hours: Delivered (g)	Megawatt Hours: Net Difference (h)	Amount of Settlement (i)
1	NONASSOCIATED								
2	UTILITIES	(a)							
3									
4	Carolina Power &								
5	Light Co.	(b)	95	Rocky Mount,					
6				Henderson(c),	115,000 (d)				
7				Greenville & Farm-		970,483	261,845	708,638	$ 5,616,103
8				ville, N.C.	230,000				
9				Carson & Halifax, Va.	500,000				
10	Appalachian Power								
11	Co.	(b)	7	Cloverdale, Va.	500,000				
12				Altavista, Bremo,		2,715,560	183,744	2,531,816	85,997,015
13				Va. &	138,000				
14				Hinton, W.Va.					
15				Philpott, Va.	138,000	(e)	16,142	(16,142)	
16				New Castle, Va.	34,500	11,154(f)		11,154	
17				Gladstone, Va.	46,000	9,720(f)		9,720	
18				Piney River, Va.	46,000	20,356(f)		20,356	
19				White House, Va.	12,500	16,279(f)		16,279	
20				Bearskin, Va.	138,000	123,284(f)		123,284	
21									
22									
23									

Next Page is 332

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1982

SUMMARY OF INTERCHANGE ACCORDING TO COMPANIES AND POINTS OF INTERCHANGE
(Included in Account 555)

Line No.	Name of Company (a)	Interchanges Across State Lines (b)	FERC Rate Schedule Number (c)	Point of Interchange (d)	Voltage at Which Interchanged (e)	Megawatt Hours: Received (f)	Megawatt Hours: Delivered (g)	Megawatt Hours: Net Difference (h)	Amount of Settlement (i)
1									
2				Red Hill, Va.	13,200	(6,851)(f)		(6,851)	
3				Stone Coal Gap, Va.	34,500	10,533(f)		10,533	
4				Schuyler, Va.	46,000	2,160(f)		2,160	
5				Scottsville, Va.	46,000	4,304(f)		4,304	
6									
7	Allegheny Power								
8	System		75	Mt. Storm, W.Va. &					
9				Doubs, Md. (g)	500,000	670,665	296,325	374,340	$9,333,911
10									
11	Potomac Edison								
12	Power Co.		71	Fishers Hill, Va.	34,500	18,182		18,182	
13				Hazel, Va.	34,500		2,242	(2,242)	
14				Milville, Va.	34,500	62,439		62,439	
15				Decapolis, Va.	34,500	15,916		15,916	
16				Somerset, Va.	34,500		59,328	(59,328)	
17				N. Shenandoah, Va.	115,000		53,531	(53,531)	
18	PJM Group	X	73	Dickerson, Md. (g)	230,000	76,087	96,176	(20,089)	2,415,973
19									
20	Potomac Electric								
21	Power Co.			Dickerson, Md. (g)	230,000				42,215
22									
23	OTHER PUBLIC								
14	AUTHORITIES								
15	Southeastern								
16	Power Adm.	(b)	100	Kerr Hydro, Va.(h)	115,000	289,629	333,879	(44,250)	(282,459)
17				Kerr Transfer CP&L		134,183		134,183	
18	OPERATING								
19	REGULATION (i)	(b)		Various	Various	45,947	46,464	(517)	
20									
21									
22									
23									

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

SUMMARY OF INTERCHANGE ACCORDING TO COMPANIES AND POINTS OF INTERCHANGE
(Included in Account 555)

Line No.	Name of Company (a)	Interchanges Across State Lines (b)	FERC Rate Schedule Number (c)	Point of Interchange (d)	Voltage at Which Interchanged (e)	Megawatt Hours Received (f)	Megawatt Hours Delivered (g)	Megawatt Hours Net Difference (h)	Amount of Settlement (i)
1	MUNICIPALITIES								
2	N.C.E. Muni.			Not Applicable	Not Applic.	212	634,195	(633,983)	$ (274,026)
3									
4	OTHER NONUTILITIES								
5	West Va. Pulp &								
6	Paper Co.			Covington	Not Applic.	130,416		130,416	9,106,102
7	Continental Forest			Hopewell, Va.	Not Applic.	301,398		301,398	21,708,539
8	City of Richmond			Richmond, Va.	Not Applic.	5,586		5,586	252,117
9	Burnshire			Woodstock, Va.	Not Applic.	690		690	34,297
10	Harris Bridge			Schuyler, Va.	Not Applic.	65		65	
11				Totals		5,628,397	1,983,871	3,644,526	133,949,787
12									
13									
14									
15									

(a) The nonassociated utilities are so interconnected that classification of power flow of kilowatt-hours through individual delivery points is not feasible. Interconnection points enumerated are those of the company with which the transaction was scheduled.

(b) Certain energy may have been interchanged across state line.

(c) Henderson interconnection point located on Virginia-North Carolina state line.

(d) Voltage at which interchanged: Rocky Mount (No. 1-115,000; No. 2-230,000; No. 3-230,000), Henderson 115,000, Farmville - 115,000, Greenville - 230,000, Carson - 500,000, and Halifax - 230,000.

(e) Power transfer - Received by Vepco at Philpott, delivered to APCo which in turn delivers to Vepco through its major interconnections.

(f) Transfer-Power received based on meter quantities. Power delivered over major interconnections are classified quantities. Difference is maintained in storage account.

(g) Doubs and Dickerson Interconnection points located on Virginia - Maryland state line.

(h) Shown in detail on pages 328-D and 328-F inclusive.

(i) Deviation from schedule with neighboring utilities.

See page 328-C for Particulars of Settlements for Interchange Power.

Annual report of Virginia Electric and Power Company — Year ended December 31, 19 82

B. Details of Settlement for Interchange Power

Name of company (j)		Explanation (k)	Amount (l)
Carolina Power & Light Co.	Received:	Economy A energy $9,751,499; Economy B energy $472,179; Emergency energy $297,496; Short-Term energy $21,964 Total: $10,543,138	
	Delivered:	Economy A energy $1,561,397; Economy B energy $196,024; Emergency energy $314,886; Reserve energy $227,734; Short-Term capacity $787,125; Short-Term energy $1,804,013; Other energy $35,856 Total: $4,927,035	$ 5,616,103
Appalachian Power Co.	Received:	Economy A energy $26,380,399; Economy B energy $19,380,293; Emergency energy $1,503,633; Short-Term capacity $8,653,304; Short-Term energy $24,353,509; Non-Displacement energy $5,735,307 Total: $86,006,445	
	Delivered:	Emergency energy $9,430	85,997,015
Allegheny Power System	Received:	Economy energy $7,996,392; Diversity energy $11,133,719 Total: $19,130,111	
	Delivered:	Emergency energy $664,544; Diversity energy $9,131,656 Total $9,796,200	9,333,911
PJM	Received:	Economy energy $3,011,302; Emergency capacity $38,262; Emergency energy $1,989,408 Total: $5,038,972	
	Delivered:	Economy energy $2,622,999	2,415,973
North Carolina Eastern Municipal Power Agency	Received:	Ecomomy energy $4,188	
	Delivered:	Emergency energy $278,214	(274,026)
Potomac Electric Power Co.		Facilities Charge	42,215
West Va. Pulp & Paper Co.	Received	Co-Generation energy	9,106,102
Continental Forest	Received:	Co-Generation energy	21,708,539
City of Richmond	Received:	Co-Generation energy	252,117
Burnshire	Received	Small Power Producer	34,297
Southeastern Power Adm.	Delivered:	Deficiency	(282,459)
			$133,949,787

INTERCHANGE POWER (ACCOUNT 555)

Name of Company	Point of Interchange	Nominal Voltage at Which Delivered	Megawatt-hours Received	Megawatt-hours Delivered
Southeastern Power Administration	Kerr Dam, Va.	115,000	289,629	7,899
Mecklenburg Elec. Co-op	Boydton, Va.	115,000		
	Crystall Hill, Va.	115,000		
	Northview, Va.	115,000		
	Jones Store, Va.	69,000		
	Gretna, Va.	69,000		
	Beechwood, Va.	115,000		
	Mt. Airy, Va.	69,000		
	Omega, Va.	115,000		
	Emporia, Va.	115,000		41,124
	Gasburg, Va.	69,000		
	Black Branch, Va.	69,000		
	Climax, Va.	69,000		
	Freeman, Va.	115,000		
	Grit, Va.	115,000		
	Brink, Va.	115,000		
	Hickory Grove, Va.	115,000		
	Clarksville, Va.	115,000		
	Barnes Junction, Va.	115,000		
	Shockoe, Va.	115,000		
Shenandoah Valley Elec. Co-op	Dayton, Va.	115,000		
	Crimora, Va.	23,000		
	Brands, Va.	115,000		
	Sherando, Va.	115,000		
	Mt. Jackson, Va.	34,500		
	Gardner Springs, Va.	23,000		
	Timberville, Va.	115,000		35,607
	Cold Springs, Va.	23,000		
	Elkton, Va.	34,500		
	North River, Va.	115,000		
	Trimbles Mill, Va.	115,000		
	Columbia Furnace, Va.	23,300		
	Woodstock, Va.	34,500		

INTERCHANGE POWER (ACCOUNT 555)

Name of Company	Point of Interchange	Nominal Voltage at Which Delivered	Megawatt-hours Received	Megawatt-hours Delivered
Southeastern Power Administration (continued)				
Community Elec. Co-op	Capron, Va.	34,500		
	Courtland, Va.	13,200		
	Holland, Va.	115,000		
	Lummus, Va.	12,500		
	Pagan, Va.	13,200		15,547
	Sadlers, Va.	13,200		
	Windsor, Va.	34,500		
	Handsom, Va.	115,000		
	Black Creek, Va.	13,200		
	Harrells, Va.	12,500		
Rappahanock Elec. Co-op	Bear Island, Va.	230,000		
	Culpeper #1, Va.	12,500		
	Culpeper #2, Va.	12,500		
	Decapolis, Va.	34,500		
	Warrenton, Va.	34,500		
	Orange, Va.	12,500		
	Dunnes, Va.	34,500		
	Oak Shade, Va.	34,500		
	Gold Mine, Va.	12,500		
	Rixley, Va.	12,500		
	Brandy, Va.	115,000		
	Orleans, Va.	34,500		
	St. John's Church, Va.	115,000		
	Miller's Tavern, Va.	34,500		55,667
	Hustle, Va.	12,500		
	Locust Grove, Va.	115,000		
	North Doswell, Va.	12,500		
	Paytes, Va.	34,500		
	Wilderness, Va.	12,500		
	Unionville, Va.	13,200		
	Cuckoo, Va.	12,500		
	Woodpecker, Va.	115,000		
	Orchid, Va.	12,500		
	Kings Dominion, Va.	115,000		
	White Shop, Va.	13,200		
	Slabtown, Va.	12,500		
	Deerfield, Va.	34,500		
	Greenwood, Va.	115,000		

INTERCHANGE POWER (ACCOUNT 555)

Name of Company	Point of Interchange	Nominal Voltage at Which Delivered	Megawatt-hours Received	Megawatt-hours Delivered
Southeastern Power Administration (Continued)				
Prince George Elec. Co-op	Prince George, Va.	13,200		
	Disputanta, Va.	13,200		
	Beechland, Va.	34,500		
	Wakefield, Va.	13,200		
	Wilkerson's Corner, Va.	13,200		
	Waverly, Va.	13,200		
	River's Edge, Va.	13,200		7,522
	Spring Grove, Va.	13,200		
	Bacon's Castle, Va.	12,500		
	Booker, Va.	13,200		
	Rowanta, Va.	13,200		
	Garysville, Va.	13,200		
Southside Electric Co-op	Lone Gum, Va.	69,000		
	Drakes Branch, Va.	12,500		
	Altavista, Va.	12,500		
	Fort Pickett, Va.	115,000		
	Madisonville, Va.	34,500		
	Danieltown, Va.	69,000		
	Perth, Va.	12,500		
	Gladys, Va.	69,000		
	Moran, Va.	115,000		
	Center Star, Va.	34,500		
	Nutbush, Va.	115,000		
	Amelia, Va.	34,500		
	Evergreen, Va.	34,500		
	Hancock, Va.	115,000		50,151
	Powhatan, Va.	34,500		
	Red House, Va.	115,000		
	Cherry Hill, Va.	34,500		
	Evington, Va.	115,000		
	Gary, Va.	115,000		
	Stoddert, Va.	34,500		
	White House, Va.	12,500		
	Pointon, Va.	34,500		
	Reams, Va.	34,500		
	Hooper, Va.	115,000		
	Martins, Va.	115,000		
	Gills, Va.	34,500		

INTERCHANGE POWER (ACCOUNT 555)

Name of Company	Point of Interchange	Nominal Voltage at Which Delivered	Megawatt-hours Received	Megawatt-hours Delivered
Southeastern Power Administration (Continued)				
B.A.R.C. Elec. Co-op	Callaghan, Va.	46,000		
	Goshen, Va.	46,000		
	East Lexington, Va.	12,500		13,541
	Bustleburg, Va.	12,500		
	Bells Valley, Va.	12,500		
	Fancy Hill, Va.	12,500		
	Cornwall, Va.	46,000		
Craig-Botetourt Elec. Co-op	Eagle Rock, Va.	46,000		
	Sweet Chalybeate, Va.	46,000		
	New Castle, Va.	34,500		6,018
	Potts Creek, Va.	12,500		
	Stone Coal Gap, Va.	34,500		
Central Virginia Elec. Co-op	Mt. Rush, Va.	34,500		
	Piney River, Va.	46,000		
	Appomattox, Va.	12,500		
	Cartersville, Va.	34,500		
	Columbia, Va.	12,500		
	Gladstone, Va.	46,000		
	Kidds Store, Va.	115,000		
	Midway, Va.	115,000		23,571
	White Hall, Va.	23,000		
	Pamplin, Va.	23,000		
	Trice's Lake, Va.	115,000		
	Cash's Corner, Va.	115,000		
	Scottsville, Va.	46,000		
	Doubleday-Madison Run, Va.	115,000		
	Curdsville, Va.	115,000		
	Schuyler, Va.	46,000		
	Trevilians, Va.	34,500		

INTERCHANGE POWER (ACCOUNT 555)

Name of Company	Point of Interchange	Nominal Voltage at Which Delivered	Megawatt-hours Received	Megawatt-hours Delivered
Southeastern Power Administration (Continued)				
Northern Neck Elec. Co-op	Cross Hill, Va.	12,500		
	Folly, Va.	34,500		
	Oak Grove, Va.	34,500		
	Office Hall, Va.	12,500		13,039
	Passapatanzy, Va.	12,500		
	Garner, Va.	34,500		
	Sanders, Va.	34,500		
Prince William Elec. Co-op	Heflin, Va.	13,200		
	Independent Hill, Va.	115,000		12,532
	Sowego, Va.	115,000		
Edgecombe-Martin Co. Elec. Corp.	Parmele, N.C.	115,000		
	Mayo-Dunbar, N.C.	115,000		
	Fountain, N.C.	12,500		
	Tarboro, N.C.	115,000		12,33[illegible]
	Hamilton, N.C.	34,500		
	Leggetts Cross Roads, N.C.	12,500		
	Wilson-Robersonville, N.C.	13,200		
	Wiggins Cross Roads, N.C.	12,500		
	Benson, N.C.	12,500		
	Conetoe, N.C.	115,000		
Albemarle Elec. Corp.	Camden, N.C.	13,200		
	Burgess, N.C.	34,500		
	Elizabeth City, N.C.	34,500		
	Edenton, N.C.	34,500		
	Morgans Corner, N.C.	13,200		8,026
	Winfall, N.C.	34,500		
	South Mills, N.C.	13,200		
	Weeksville, N.C.	34,500		
	Cisco, N.C.	34,500		

INTERCHANGE POWER (ACCOUNT 555)

Name of Company	Point of Interchange	Nominal Voltage at Which Delivered	Megawatt-hours Received	Megawatt-hours Delivered
Southeastern Power Administration (Continued)				
Halifax Elec. Corp.	Scotland Neck, N.C.	12,500		
	Medoc, N.C.	34,500		
	Enfield, N.C.	115,000		6,519
	Eaton's Ferry, N.C.	12,500		
	Sam's Head, N.C.	12,500		
	Dawson, N.C.	12,500		
Roanoke Elec. Corp.	Aulander, N.C.	34,500		
	Conway, N.C.	34,500		
	Eason's Cross Roads, N.C.	12,500		
	Gum Fork, N.C.	34,500		
	Windsor, N.C.	34,500		20,060
	Halifax, N.C.	115,000		
	Merry Hill, N.C.	34,500		
	Roduco, N.C.	34,500		
	Jackson, N.C.	115,000		
	Woodville, N.C.	34,500		
Tideland Elec. Corp.	Plymouth, N.C.	34,500		
	Pantego, N.C.	34,500		6,018
	Five Points, N.C.	34,500		
	Fairfield, N.C.	34,500		
	Total		289,629	333,879

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1982

TRANSMISSION OF ELECTRICITY FOR OR BY OTHERS (Accounts 456 and 565)

(Including transactions sometimes referred to as "wheeling")

1. Describe below and give particulars of any transactions by respondent during the year for transmission of electricity for or by others during year, including transactions sometimes referred to as wheeling.

2. Provide separate subheadings for: (a) *Transmission of Electricity for Others* (included in Account 456) and (b) *Transmission of Electricity by Others* (Account 565).

3. Furnish the following information in the space below concerning each transaction:
   (a) Name of company and description of service rendered or received. Designate associated companies.
   (b) Points of origin and termination of service specifying also any transformation service involved.
   (c) MWh received and MWh delivered.
   (d) Monetary settlement received or paid and basis of settlement, included in Account 456 or 565.
   (e) Nonmonetary settlement, if any, specifying the MWh representing compensation for the service, specifying whether such power was firm power, dump or other power, and state basis of settlement. If nonmonetary settlement was other than MWh describe the nature of such settlement and basis of determination.
   (f) Other explanations which may be necessary to indicate the nature of the reported transactions. Include in such explanations a statement of any material services remaining to be received or furnished at end of year and the accounting recorded to avoid a possible material distortion of reported operating income for the year.

TRANSACTIONS WITH SOUTHEASTERN POWER ADMINISTRATION

(Account 456)

The Virginia Electric and Power Company (Vepco) provides or contracts for the use of such transmission facilities as may be required to transmit certain generation at the Kerr and Philpott Hydro Projects into the Company's transmission system, and through the same to customers of the Southeastern Power Administration (Sepa). For accounting and billing purposes the total output of the Philpott Project and the deficiency energy sold to Sepa by Vepco are deemed to originate at the Kerr Project.

Vepco receives electrical energy at the Kerr Project for the account of Sepa and makes the following deliveries:

* 1. Customers of Sepa in the Vepco service area consisting of 184 delivery points as enumerated under "Interchange Power (Account 555)". Vepco receives a zone rate of 1.0 mill per kilowatt-hour for energy delivered within 100 miles and 1.75 mills per kilowatt-hour for energy delivered between a 100 and 150 mile radius of the Kerr Project. Wheeling fees are collected on energy delivered to cooperatives from Kerr generation, but does not include deficiency energy.

* 2. Carolina Power & Light Company at (for accounting purposes) the Virginia-North Carolina state line in the vicinity of the Kerr Project. For deliveries so made Vepco receives compensation at the rate of 0.07 mills per kilowatt-hour.

In addition to the above Vepco receives $5,000 per month as reimbursement for the cost of providing and obtaining the transmission and other services necessary to the utilization in the Vepco system of Philpott Project power on an integrated basis with Kerr Project.

Transactions are tabulated below:

Received Mwh	Received from Southeastern Power Administration delivered to:	Delivered Mwh	Account 456 Amount
280,303	Southeastern Customers in Virginia Electric and Power Company's Service Area	325,980 (a)	$351,976
134,183	Carolina Power & Light Company	133,785	9,192
- - -	Philpott Project Intergration		60,000
			$421,168

(a) Includes 56,492 Mwh Deficiency Energy purchased from Vepco.

Note: Difference between delivered and received Mwh includes allowance for loss to Vepco for wheeling energy and the generation of the storage account for Southeastern Power Administration customers in Virginia Electric and Power Company's service area.

* REVISIONS ACCORDING TO THE NEW SEPA CONTRACT EFFECTIVE DECEMBER 30, 1982

Vepco receives energy at the Kerr Project for the account of SEPA and makes the following deliveries:

1. Customers of SEPA in the Vepco service area consisting of 184 delivery points as enumerated under "Interchange Power (Account 555)." Vepco receives compensation from the Government at a rate of $1.74 per kilowatt month to deliver 136,700 kilowatts of net capacity each month.
2. Carolina Power and Light Company at (for accounting purposes) the Virginia-North Carolina state line in the vicinity of the Kerr Project. For deliveries so made, Vepco receives compensation of $1,000.00 per month.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec 31, 1982

TRANSMISSION OF ELECTRICITY FOR OR BY OTHERS (Accounts 456 and 565)
(Including transactions sometimes referred to as "wheeling")

1. Describe below and give particulars of any transactions by respondent during the year for transmission of electricity for or by others during year, including transactions sometimes referred to as wheeling.
2. Provide separate subheadings for: (a) *Transmission of Electricity for Others* (included in Account 456) and (b) *Transmission of Electricity by Others* (Account 565).
3. Furnish the following information in the space below concerning each transaction:
   (a) Name of company and description of service rendered or received. Designate associated companies.
   (b) Points of origin and termination of service specifying also any transformation service involved.
   (c) MWh received and MWh delivered.
   (d) Monetary settlement received or paid and basis of settlement, included in Account 456 or 565.
   (e) Nonmonetary settlement, if any, specifying the MWh representing compensation for the service, specifying whether such power was firm power, dump or other power, and state basis of settlement. If nonmonetary settlement was other than MWh describe the nature of such settlement and basis of determination.
   (f) Other explanations which may be necessary to indicate the nature of the reported transactions. Include in such explanations a statement of any material services remaining to be received or furnished at end of year and the accounting recorded to avoid a possible material distortion of reported operating income for the year.

TRANSACTIONS WITH NORTH CAROLINA EASTERN MUNICIPAL POWER AGENCY (NCEMPA)
(Account 456)

On December 30, 1981, the service agreement between Vepco and serveral North Carolina municipalities was terminated. Coincidently, the North Carolina Eastern Municipal Power Agency (Power Agency) became the bulk power supplier for these municipalities in North Carolina.

The Power Agency has purchased portions of electric generating units from Carolina Power and Light Company. From December 30, 1981, the initial termination of service date, through December 30, 1982, the Power Agency will receive 69 percent of its ultimate capacity entitlement from CP&L for delivery to its municipal customers. From December 31, 1982 through December 30, 1983, the Power Agency will receive all of its ultimate capacity entitlement from CP&L for delivery to its municipal customers. Approximately 33.5 percent of the capacity entitlement for each period is considered available to the Power Agency's municipal customers in Vepco's service territory. During the transition period, Vepco will supply to Power Agency's municipal customers in Vepco's service territory that portion of the Power Agency's load in excess of the Power Agency's available capacity entitlement from CP&L allocated among Power Agency's customers in the Vepco service area. Vepco will also provide transmission service during the transition period and thereafter. For transmission services, Vepco is reimbursed as follows:

1. Power Agency will pay Vepco a monthly transmission service charge of $1.433 per kilowatt based on the maximum capacity transmitted at 69 KV or above during the month (excluding Schedule RS-A capacity).
2. Power Agency will pay Vepco a monthly transmission service charge of $1.923 per kilowatt of capacity transmitted at voltages of less than 69 KV during the month.

Transactions are tabulated below:

RECEIVED MWH	RECEIVED FROM NORTH CAROLINA EASTERN MUNICIPAL POWER AGENCY AND DELIVERED TO	DELIVERED MWH	ACCOUNT 456 AMOUNT
653,130(a)	North Carolina Eastern Municipal Power Agency customers in Virginia Electric and Power Company's Service Area	634,195(b)	-
-	North Carolina Eastern Municipal Power Agency customers in Virginia Electric and Power Company's Service Area (Transmission Service Charge)		$1,449,303

(a) Includes 21[illegible] MWH of economy energy purchased by Virginia Electric and Power Company.
(b) Includes 60[illegible]0 MWH of emergency energy purchased from Virginia Electric and Power Company.

Note: Difference between delivered and received MWH includes allowance for losses to Vepco for wheeling energy to North Carolina Eastern Municipal Power Agency customers in Vepco's service area.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric & Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	$ 687,766
2	Nuclear Power Research Expenses	–
3	Other Experimental and General Research Expenses	6,810,677
4	Publishing and Distributing Information and Reports to Stockholders; Trustee, Registrar, and Transfer Agent Fees and Expenses, and Other Expenses of Servicing Outstanding Securities of the Respondent	1,555,384
5	Other Expenses *(List items of $5,000 or more in this column showing the (1) purpose, (2) recipient and (3) amount of such items. Group amounts of less than $5,000 by classes if the number of items so grouped is shown)*	8,082,914
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7	See detail on pages 333-1 and 333-2.	
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46	TOTAL	$ 17,136,741

MISCELLANEOUS GENERAL EXPENSES (ACCOUNT 930.2) (ELECTRIC)
DETAIL OF OTHER EXPENSES - LINE 5, PAGE 333

Purpose	Recipient	Amount
1. Fees and Expenses - directors' meetings	John B. Bernhardt	$ 15,151
	James F. Betts	14,155
	Milton L. Drewer, Jr.	15,273
	Mary C. Fray	15,098
	Bruce C. Gottwald	11,088
	Dr. Allix B. James	14,635
	William S. Peebles, III	14,916
	Shirley S. Pierce	13,161
	Kenneth A. Randall	16,902
	William T. Roos	14,347
	Roy R. Smith	13,733
	William F. Vosbeck, Jr.	14,410
Miscellaneous Expenses associated with directors' meetings	Various	24,428
		197,297
2. Contributions to rescue squads and volunteer fire departments	Isle of Wight Vol. Rescue Squad	1,000
	Surry Vol. Rescue Squad	1,000
	Smithfield Vol. Fire Department	1,000
	LCP Chemicals, Inc.	1,400
	Bensley - Bermuda Vol. Fire Dept.	1,000
	Various items less than $1,000 each	11,968
		17,368
3. Chambers of Commerce	Portsmouth	1,120
	Norfolk	3,465
	Alexandria	1,200
	Fairfax County	1,200
	Arlington	1,200
	The Metro	15,000
	Virginia Beach	3,312
	Peninsula	1,440
	Various items under $1,000 each	15,969
		43,906
4. Write-off of canceled construction projects		101,894
5. Company's contribution or dues	Nuclear Electric Insurance	6,558,626
	Edison Electric Institute (EEI)	152,234
	Institute of Nuclear Power Operation	603,850
		7,314,710

MISCELLANEOUS GENERAL EXPENSES (ACCOUNT 930.2) (ELECTRIC)
DETAIL OF OTHER EXPENSES - LINE 5, PAGE 333
(Continued)

	Purpose	Amount
6.	Payroll, transportation and miscellaneous charges relative to general business matters	$ 24,331
7.	Survey Reclassification	289,253
8.	Miscellaneous	70,383
9.	Customer Advisory Board	23,772
	TOTAL	$8,082,914

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric & Power Co	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Accounts 403, 404, 405)
(Except amortization of acquisition adjustments)

1. Report in Section A for the year the amounts for: (a) *Depreciation Expense* (Account 403); (b) *Amortization of Limited-Term Electric Plant* (Account 404); and (c) *Amortization of Other Electric Plant* (Account 405).

2. Report in section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute the charges and whether any changes have been made in the basis or rates used from the preceding report year.

3. Report all available information called for in section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of section C the type of plant included in any subaccounts used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional classifications and showing a composite total. Indicate at the bottom of section C the manner in which column (b) balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant.

If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization of Limited-Term Electric Plant (Acct. 404) (c)	Amortization of Other Electric Plant (Acct. 405) (d)	Total (e)
1	Intangible Plant		$1,803,881		$1,803,881
2	Steam Production Plant	$38,077,368			38,077,368
3	Nuclear Production Plant	76,491,452			76,491,452
4	Hydraulic Production Plant—Conventional	1,134,790			1,134,790
5	Hydraulic Production Plant—Pumped Storage				
6	Other Production Plant	187,251			187,251
7	Transmission Plant	17,681,621			17,681,621
8	Distribution Plant	48,828,993			48,828,993
9	General Plant	1,966,525			1,966,525
10	Common Plant—Electric	1,064,756			1,064,756
11	TOTAL	185,432,756	1,803,881		187,236,637

B. Basis for Amortization Charges

(c) Includes computer Software Amortization of $1,800,659 and Amortization of Leasehold improvement in the amount of $3,222.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rate(s) (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
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26							
27			No Change in Data filed in 1981 Report				
28			For Columns (c) through (g).				
29			Data For Column (b) Due to be filed				
30			Again in 1986 Report.				
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges (Continued)

Line No	Account No (a)	Depreciable Plant Base (In thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rate(s) (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) *Miscellaneous Amortization* (Account 425)—Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) *Miscellaneous Income Deductions*—Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) *Interest on Debt to Associated Companies* (Account 430)—For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) *Other Interest Expense* (Account 431)—Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1		
2	See pages 337A-337D	
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Miscellaneous Income Deductions (Account 426.1 - 426.5)

Account 426.1 - Donations - See page 337-B and C	$ 511,299
Account 426.2 - Life Insurance	
Equitable Life Assurance Society of the United States - Supplemental Life Insurance for various executives	206,963
Account 426.3 - Penalties	
U.S. Nuclear Regulatory Commission - Civil	50,000
12 items each less than $1,000	2,667
Total Account 426.3	52,667
Account 426.4 - Expenditures for Certain Civic, Political and Related Activities	
Lobbying and other expenses concerned with following matters that affect the interests and operations of the Company in the following jurisdictions:	
Virginia	8,309
North Carolina	5,945
Federal	49,723
Political Action Committee expenses (including the Committee for Responsible Government Newsletter)	7,704
Dues - Edison Electric Institute	12,250
Salaries - political activities	21,043
Campaign Support - Arkansas Issues Committee	5,000
Donation - Citizens' Legislative Committee	1,000
Miscellaneous - various items each less than $1,000	2,037
Total Account 426.4	113,011
Account 426.5 - Other	
Dues, civic and other organizations of immaterial individual amounts	61,847
Yorktown Unit 3 implosion settlement	634,478
Miscellaneous	23,686
Total Account 426.5	720,011
Total Accounts 426.1 - 426.5	$1,603,951

OTHER INCOME DEDUCTIONS - DONATIONS (ACCOUNT 426.1)

Recipient	Address	Amount
I. Health and Welfare		
A. United Way		
1. Norfolk - Four Cities	Norfolk, Virginia	$ 84,750
2. Greater Richmond	Richmond, Virginia	82,275
3. National Capital Area	Washington, D.C.	74,625
4. Newport News (Peninsula)	Newport News, Virginia	19,975
5. Petersburg	Petersburg, Virginia	7,885
6. Charlottesville and Albemarle County	Charlottesville, Virginia	7,141
7. Staunton and Augusta County	Staunton, Virginia	2,669
8. Greater Williamsburg	Williamsburg, Virginia	2,284
9. Waynesboro and East Augusta	Waynesboro, Virginia	2,105
10. Rappahannock	Rappahannock, Virginia	2,085
11. Hopewell	Hopewell, Virginia	1,877
12. Harrisonburg and Rockingham County	Harrisonburg, Virginia	1,685
13. Greater Alleghany	Alleghany, Virginia	1,635
14. Suffolk	Suffolk, Virginia	1,606
15. Halifax County	Halifax, Virginia	1,581
16. Pasquotank County - Elizabeth City	Elizabeth City, North Carolina	1,035
17. 13 items each less than $1,000	Various Locations	4,531
		$ 299,744
B. Red Cross		
1. 47 items each less than $1,000	Various Locations	$ 1,570
C. Hospitals		
1. Norfolk General Hospital	Norfolk, Virginia	$ 20,000
2. Arlington Hospital	Arlington, Virginia	1,000
3. Junior Board of the Virginia Home	Richmond, Virginia	100
		$ 21,100
D. Other Health and Welfare		
1. St. John Vianney Center	Richmond, Virginia	$ 5,000
2. Rappahannock Area YMCA	Fredericksburg, Virginia	1,500
3. Virginia Council on Health and Medical Care	Richmond, Virginia	1,000
4. 10 items each less than $1,000	Various Locations	2,982
		$ 10,482
Total Health and Welfare		$ 332,896
II. Education		
A. College Funds		
1. Virginia Foundation for Independent Colleges	Lynchburg, Virginia	$ 37,160
2. Virginia College Fund	Richmond, Virginia	5,405
3. Independent College Fund of North Carolina	Winston-Salem, North Carolina	5,000
4. United Negro College Fund, Inc.	New York, New York	3,500
5. West Virginia Foundation for Independent Colleges, Inc.	Charleston, West Virginia	600
		$ 51,665
B. College Capital or Other		
1. University of Richmond	Richmond, Virginia	$ 15,000
2. Hampton Institute	Hampton, Virginia	10,000
3. University of Virginia - Energy Policies Studies Center	Charlottesville, Virginia	10,000
4. Mary Baldwin College	Staunton, Virginia	7,500
5. Randolph-Macon College	Ashland, Virginia	3,300
6. Virginia Polytechnic Institute and State University	Blacksburg, Virginia	3,000
7. Washington and Lee University	Lexington, Virginia	3,000
8. St. Paul's College	Lawrenceville, Virginia	2,000
9. 2 items each less than $1,000	Various Locations	650
		$ 54,450
C. Youth Education		
1. Virginia 4-H Club Fund	Blacksburg, Virginia	$ 6,557
2. North Carolina Engineering Foundations, Inc.	Raleigh, North Carolina	4,000
3. Southeast 4-H Educational Center	Wakefield, Virginia	4,000
4. BSA, Robert E. Lee Council	Richmond, Virginia	3,228
5. Northern Virginia 4-H Center	Front Royal, Virginia	2,500
6. Junior Achievement of Richmond, Inc.	Richmond, Virginia	2,200
7. Junior Achievement of Tidewater, Inc.	Norfolk, Virginia	2,000
8. Young People's Foundation	Louisa, Virginia	1,500
9. Junior Achievement of Metropolitan Washington, Inc.	Washington, D.C.	1,200
10. 20 items each less than $1,000	Various Locations	5,037
		$ 32,222

Virginia Electric and Power Company — Year Ended December 31, 1982

OTHER INCOME DEDUCTIONS - DONATIONS (ACCOUNT 426.1)

Recipient	Address	Amount
D. Other Education		
1. Eastern Virginia Medical Foundation	Norfolk, Virginia	$ 15,000
2. American Energy Week II	Washington, D.C.	2,500
3. Virginia Commonwealth University	Richmond, Virginia	2,000
4. Virginia Council on Economic Education	Richmond, Virginia	1,800
5. 2 items each less than $1,000	Various Locations	325
		$ 21,625
Total Education		$ 159,962
III. Culture and Art		
A. Music and Dance		
1. Richmond Ballet	Richmond, Virginia	$ 1,000
2. 8 items each less than $1,000	Various Locations	2,150
		$ 3,150
B. Museums and Theatres		
1. Virginia Stage Company	Richmond, Virginia	$ 14,050
2. Science Museum of Virginia	Richmond, Virginia	10,800
3. Chrysler Museum	Norfolk, Virginia	1,000
4. Kennedy Center Corporate Fund	Washington, D.C.	1,000
5. 6 items each less than $1,000	Various Locations	1,675
		$ 28,525
C. Public TV/Radio		
1. 2 items each less than $1,000	Various Locations	$ 750
D. Other Culture and Art		
1. Virginia Center for the Performing Arts	Richmond, Virginia	$ 30,000
2. Federated Arts Council of Richmond	Richmond, Virginia	1,500
3. Friends of Turkey Run Farm, Inc.	McLean, Virginia	1,000
4. 8 items each less than $1,000	Various Locations	2,100
		$ 34,600
Total Culture and Art		$ 67,025
IV. Civic		
A. Community Improvement		
1. Richmond Renaissance	Richmond, Virginia	$ 50,000
2. Colonial Williamsburg Foundation	Williamsburg, Virginia	2,500
3. Norfolk Salvation Army	Norfolk, Virginia	2,500
4. Peninsula Salvation Army	Newport News, Virginia	2,500
5. Salvation Army	Various Locations	2,100
6. Eastern Carolina Vocational Center, Inc.	Greensville, North Carolina	2,000
7. Harborfest Norfolk, Norfolk Chamber of Commerce	Norfolk, Virginia	1,000
8. Union League of Tidewater	Norfolk, Virginia	1,000
9. 23 items each less than $1,000	Various Locations	5,952
		$ 69,552
B. Environment		
1. 2 items each less than $1,000	Various Locations	$ 900
C. Other Civic		
1. League of Women Voters	McLean, Virginia	$ 100
Total Civic		$ 70,552
V. Miscellaneous		
A. Local		
1. American Quadricentennial Corp.	Raleigh, North Carolina	$ 5,000
2. Nautical Adventures, Inc. - Norfolk School of Boat Building	Norfolk, Virginia	1,000
3. 12 items each less than $1,000	Various Locations	3,142
		$ 9,142
B. National		
1. National Alliance of Businessmen	Norfolk, Virginia	$ 1,000
2. 3 items each less than $1,000	Various Locations	852
		1,852
Total Miscellaneous		$ 10,994
VI. Campaign Expense for United Giver's Fund		$ 17,631
Total Cash Donations		$ 659,060
VII. Miscellaneous Adjustments		$(147,761)
Total 1982 Donations		$ 511,299

Virginia Electric and Power Company

Year Ended December 31, 1982

OTHER INCOME DEDUCTIONS - OTHER INTEREST EXPENSE (ACCOUNT 431)

	Rate	Amount
Customer Deposits	8	$ 1,385,415
Short-term Debt - Other	Various	14,317,816
Revolving Credit Agreement	Various	706,927
Fees Expense - Banks	Various	611,209
Installment Purchase - Xerox Equipment	Various	3,476
Federal Income Tax Deferred	20	1,833,987
Vepco Master Note	Various	1,514,405
Refund to FERC and MS Customers	Various	(10,877)
Xerox Equipment - Grayland Avenue	Various	5,346
Bath County - Amortization of Fees	Various	1,786,203
Industrial Development Authority Pollution Control - York County	Various	175,667
Industrial Development Authority Pollution Control - York County	Various	175,903
Retirement Plan	7	326,800
Customer Stock Purchase Plan	8	303,182
Industrial Development Note	Various	192,893
Return on Funds Collected on Nuclear Decommissioning - Virginia	10.88	701,024
Refund for FERC and MS Rates - 9/1/81	Various	741,628
Present Worth - In Reactor - North Carolina	11.353	763,728
Present Worth - Spent Fuel - North Carolina	11.353	111,560
Interest on Gas Refunds	8	40,076
Time Purchase Xerox Equipment - Fairfax	Various	542
Short-term Bank Loan - Manufacturers Hanover Trust - 1/6/82	Various	9,549
Short-term Bank Loan - Industrial Bank - Japan - 1/5/82	Various	11,458
Short-term Bank Loan - Manufacturers Hanover Trust - 1/5/82	Various	6,875
Installment Purchase Xerox Equipment - System Engineering	Various	7,288
Short-term Bank Loan - United Virginia Bank - due 2/9/82	Various	3,417
North Carolina Income Tax Liability	6	1,543
Return on Funds Collected for Nuclear Decommissioning Costs - West Virginia	11.45	3,158
Return on Disposition Cost - Present Worth - Spent Fuel - West Virginia	11.45	168
Return on Disposition Cost - Present Worth - In Reactor - West Virginia	11.45	119,405
Refund for MS Customer Rates - 9/1/82	Various	10,632
Refund for FERC Customer Rates - 9/1/82	Various	31,820
Pollution Control Notes	6.5	15,226
Customer Stock Purchase Plan - 1982 - 83	8	40,167
		$25,947,616

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to formal cases before a regulatory body, or cases in which such a body was a party.

2. In columns (b) and (c), indicate whether the expenses were assessed by a regulatory body or were otherwise incurred by the utility.

Line No.	Description (*Furnish name of regulatory commission or body, the docket or case number, and a description of the case.*) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses to Date (d)	Deferred in Account 186 at Beginning of Year (e)
1					
2	FERC:				
3					
4	Filing Fees	$ 75,048			
5	Investigation Charges		$ 82,053		
6	Annual Administrative Charges	110,006			
7					
8	Electric Rate Proceedings:				
9	FERC		499,463		
10	Virginia		778,137		
11	North Carolina		776,726		
12	West Virginia		420,178		
13	Non-Jurisdictional		256,685		
14	Other		6,983		
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
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34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	$185,054	$2,820,225		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. The totals of columns (e), (i), (k), and (l) must agree with the totals shown at the bottom of page 223 for Account 186.
5. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
6. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CHARGED CURRENTLY TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 186 (i)	Contra Account (j)	Amount (k)	Deferred in Account 186, End of Year (l)	Line No.
							1
							2
							3
Electric	928	$ 75,048					4
Electric	928	82,053					5
Electric	928	110,006					6
							7
							8
Electric	928	499,463					9
Electric	928	778,137					10
Electric	928	776,726					11
Electric	928	420,178					12
Electric	928	256,685					13
Electric	928	6,983					14
							15
							16
							17
							18
							19
							20
							21
							22
							23
							24
							25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		$3,005,279					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) projects initiated, continued, or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R, D & D work carried on by the respondent in which there is a sharing of costs with others, show separately the respondent's cost for the year and cost chargeable to others. (See definition of research, development, and demonstration in Uniform System of Accounts.)

2. Indicate in column (a) the applicable classification, as shown below. Classifications:

A. Electric R, D & D Performed Internally
- (1) Generation
  - a. Hydroelectric
    - i. Recreation, fish, and wildlife
    - ii. Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) System Planning, Engineering and Operation
- (3) Transmission
  - a. Overhead
  - b. Underground
- (4) Distribution
- (5) Environment (other than equipment)
- (6) Other *(Classify and include items in excess of $5,000.)*
- (7) Total Cost Incurred

B. Electric R, D & D Performed Externally
- (1) Research Support to the Electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A. Electric Utility R. D. and D. Performed Internally	
2	(1) Generation	
3	a. Hydroelectric	
4		Biological - Chemical - Physical Studies
5		Low Head Hydro
6		Alternative Energy Sources Low Head Study - Harvell,
7		North Anna, Manchester, Mt. Storm & Sunrise
8		
9	b. Fossil	Biological - Chemical - Physical Studies
10	Fuel	New Site Studies
11	Steam	Air Monitoring Studies
12		Sulfur Dioxide Emission Monitoring System - Possum Pt.
13		Stack Emissions Monitoring Studies
14		
15		
16		Fuel Conversion Alternative - Yorktown and Possum Pt.
17		Fly Ash Structural Fill - Yorktown
18		
19		
20	d. Nuclear	Biological - Chemical - Physical Studies
21		Biological & Thermal Off-Steam Cooling - North Anna
22		Air Monitoring Studies - Surry & North Anna
23		Reactor Coolant System Behavior Model
24		Zero Dimension Code Simulator
25		Core Design & Physics Model
26		Atom 1 Core Model Development
27		
28	e. Unconventional Generation	
29		Non Conventional Fuels - Biomass, Peat, Refuse
30		Coal, Nuclear, & Gas Fired Generation
31		Combined Cycle System
32		Fuel Cells
33		Wind Turbines
34		Solar Electric
35		
36		
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others *(Classify)*
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A.(6) and B.(4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, *Construction Work in Progress*, first. Show in column (f) the amounts related to the account charged in column (e).

5. Show in column (g) the total unamortized accumulation of costs of projects. This total must equal the balance in Account 188, *Research, Development, and Demonstration Expenditures*, outstanding at the end of the year.

6. If costs have not been segregated for R, D & D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	Amounts Charged in Current Year: Account (e)	Amounts Charged in Current Year: Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
					4
$ 32,496		107	$ 32,496		5
39,058		930	39,058	$ 1	6
13,010		188	13,010	1	7
					8
					9
211,224		506	211,224		10
13,154		183	13,154		11
305,931		506	305,931		12
14,407		183	14,407		13
1,274)		107	819		14
)		514	368		15
)		920	87		16
2,753		183	2,753		17
161,692		101	161,692		18
					19
297,880		524	297,880		20
80,811		524	80,811		21
61,080		524	61,080		22
5,289		524	5,289		23
837		524	837		24
18,050		524	18,050		25
13,836		524	13,836		26
					27
					28
131,321		186	131,321	5	29
75,528		186	75,528	5	30
49,448		186	49,448	5	31
65,457		186	65,457	5	32
75,718		186	75,718	5	33
62,530		186	62,530	16	34
					35
					36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) projects initiated, continued, or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R, D & D work carried on by the respondent in which there is a sharing of costs with others, show separately the respondent's cost for the year and cost chargeable to others. (See definition of research, development, and demonstration in Uniform System of Accounts.)

2. Indicate in column (a) the applicable classification, as shown below. Classifications:

A. Electric R, D & D Performed Internally
  (1) Generation
    a. Hydroelectric
      i. Recreation, fish, and wildlife
      ii. Other hydroelectric
    b. Fossil-fuel steam
    c. Internal combustion or gas turbine
    d. Nuclear
    e. Unconventional generation
    f. Siting and heat rejection
  (2) System Planning, Engineering and Operation
  (3) Transmission
    a. Overhead
    b. Underground
  (4) Distribution
  (5) Environment (other than equipment)
  (6) Other *(Classify and include items in excess of $5,000.)*
  (7) Total Cost Incurred

B. Electric R, D & D Performed Externally
  (1) Research Support to the Electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	(2) System Planning, Engineering and Operation	
2		Heat Loss
3		Heat Pump Efficiency
4		End Use Solar
5		Load Management
6		Cogeneration
7		Alternative Energy Study - Misc.
8		Coal Slurry Pipeline
9		Office System Pilot Study
10		Metering & Load Management
11		Add-on Heat Pumps
12		Energy Saver Home Program
13		LGS Interruptible Rate Study
14		
15	(4) Distribution	Testing at R & D Facility
16		
17		Time of Usage Metering
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		Aluminum Concentric Neutral Cable
30		
31	(7) Total Cost Incurred	
32		
33		
34		
35		
36		
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1982

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others *(Classify)*
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A.(6) and B.(4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, *Construction Work in Progress*, first. Show in column (f) the amounts related to the account charged in column (e).

5. Show in column (g) the total unamortized accumulation of costs of projects. This total must equal the balance in Account 188, *Research, Development, and Demonstration Expenditures*, outstanding at the end of the year.

6. If costs have not been segregated for R, D & D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year *(c)*	Costs Incurred Externally Current Year *(d)*	AMOUNTS CHARGED IN CURRENT YEAR Account *(e)*	Amount *(f)*	Unamortized Accumulation *(g)*	Line No.
					1
$ 42,167		186	$ 42,167		2
60,457		186	60,457		3
43,531		186	43,531		4
9,663		186	9,663		5
67,302		186	67,302		6
397,805		186	397,805		7
188,997		183	188,997		8
91,033		188	91,033	$ 91,033	9
1,654		183	1,654		10
9,567		186	9,567		11
9,555		186	9,555		12
3,770		186	3,770		13
					14
94,349(		566	47,175		15
(		588	47,174		16
137,445)		586	10,173		17
)		587	34,651		16
)		588	19,631		19
)		597	14,404		20
)		598	16,135		21
)		902	22,923		22
)		907	2,028		23
)		908	14,685		24
)		910	2,791		25
)		932	24		26
					27
					28
623		101	623		29
					30
$2,890,702			$2,890,702		31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1982

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) projects initiated, continued, or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R, D & D work carried on by the respondent in which there is a sharing of costs with others, show separately the respondent's cost for the year and cost chargeable to others. (See definition of research, development, and demonstration in Uniform System of Accounts.)

2. Indicate in column (a) the applicable classification, as shown below. Classifications:

A. Electric R, D & D Performed Internally
 (1) Generation
  a. Hydroelectric
   i. Recreation, fish, and wildlife
   ii. Other hydroelectric
  b. Fossil-fuel steam
  c. Internal combustion or gas turbine
  d. Nuclear
  e. Unconventional generation
  f. Siting and heat rejection
 (2) System Planning, Engineering and Operation
 (3) Transmission
  a. Overhead
  b. Underground
 (4) Distribution
 (5) Environment (other than equipment)
 (6) Other *(Classify and include items in excess of $5,000.)*
 (7) Total Cost Incurred
B. Electric R, D & D Performed Externally
 (1) Research Support to the Electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	B. Electric Utility R. D. and D. Performed Externally	
2	(1) Research Support to the Electric Power Research Institute	
3		Retran Code Model Development
4		Cobra/Vipre Code Model Development
5		EPRI Participation - Fuel Resources
6		EPRI - Power Valve Test Program
7		USAS Code Model Testing & Modeling
8		EPRI - XLPE Insulated Cable for Low Temp. Application
9		
10	(2) Research Support to Edison Electric Institute	
11		
12	(4) Research Support to Others	
13		V.P.I. & S. U. Energy Research Group
14		Union Carbide - DOE Research Project
15		
16		
17		
18		Pumped Storage Trash Rack Design - Utah State Univ.
19		DOE High Burnup Program
20		Grant in Aid to V.P.I. & S.U.
21		North Carolina State Embrittlement of Pressure Vessels
22		Consultant - Univ. of Virginia - R & D
23		Dry Spent Fuel Storage Program - DOE
24		Corrosion Probability - Serv. Water Sys. Piping - Lehigh Univ.
25		Energy Liaison Program - Lehigh Univ.
26		Contribution to N. Carolina Alternative Energy Corp.
27		
28	(5) Total Cost Incurred	
29		
30	Total Research, Development and Demonstration	
31		
32		
33		
34		
35		
36		
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others *(Classify)*
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A.(6) and B.(4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, *Construction Work in Progress*, first. Show in column (f) the amounts related to the account charged in column (e).

5. Show in column (g) the total unamortized accumulation of costs of projects. This total must equal the balance in Account 188, *Research, Development, and Demonstration Expenditures*, outstanding at the end of the year.

6. If costs have not been segregated for R, D & D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	Amounts Charged in Current Year: Account (e)	Amounts Charged in Current Year: Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
	$ 45,710	524	$ 45,710		3
	10,492	524	10,492		4
	6,394	524	6,394		5
	299,281	524	299,281		6
	534	524	534		7
	1,443	524	1,443		8
					9
	6,716,201	930	6,716,201		10
					11
					12
					13
	13,900	930	13,900		14
	19,968)	236	193	$ 609	15
	)	588	2,701		16
	)	907	8,205		17
	)	921	8,869		18
	173,274	107	173,274		19
	26,199	524	26,199		20
	10,035	524	10,035		21
	25,000	517	25,000		22
	41,464	517	41,464		23
	1,045	524	1,045		24
	16,397	107	16,397		25
	38,391	101	38,391		26
	91,103	930	91,103		27
					28
	$7,536,831		$ 7,536,831		29
					30
$2,890,702	$7,536,831		$10,427,533	$91,685	31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to *Utility Departments, Construction, Plant Removals, and Other Accounts*, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric		(Dollars)	
2	Operation			
3	Production	54,977,393		
4	Transmission	3,739,271		
5	Distribution	33,284,158		
6	Customer Accounts	21,177,931		
7	Customer Service and Informational	3,209,160		
8	Sales			
9	Administrative and General	32,162,112		
10	TOTAL Operation *(Enter Total of lines 3 thru 9)*	148,550,025		
11	Maintenance			
12	Production	37,988,189		
13	Transmission	4,053,818		
14	Distribution	17,187,840		
15	Administrative and General	1,371,845		
16	TOTAL Maintenance *(Enter Total of lines 12 thru 15)*	60,601,692		
17	Total Operation and Maintenance			
18	Production *(Enter Total of lines 3 and 12)*	92,965,582		
19	Transmission *(Enter Total of lines 4 and 13)*	7,793,089		
20	Distribution *(Enter Total of lines 5 and 14)*	50,471,998		
21	Customer Accounts *(Transcribe from line 6)*	21,177,931		
22	Customer Service and Informational *(Transcribe from line 7)*	3,209,160		
23	Sales *(Transcribe from line 8)*			
24	Administrative and General *(Enter Total of lines 9 and 15)*	33,533,957		
25	TOTAL Operation and Maintenance *(Total of lines 18 thru 24)*	209,151,717	4,681,286	213,833,003
26	Gas			
27	Operation			
28	Production—Manufactured Gas	212,909		
29	Production—Natural Gas (Including Expl. and Dev.)			
30	Other Gas Supply			
31	Storage, LNG Terminaling and Processing			
32	Transmission			
33	Distribution	2,584,425		
34	Customer Accounts	1,572,379		
35	Customer Service and Informational	40,724		
36	Sales			
37	Administrative and General	1,989,065		
38	TOTAL Operation *(Enter Total of lines 28 thru 37)*	6,399,502		
39	Maintenance			
40	Production—Manufactured Gas	104,048		
41	Production—Natural Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing			
44	Transmission			
45	Distribution	1,461,941		
46	Administrative and General	53,308		
47	TOTAL Maintenance *(Enter Total of lines 40 thru 46)*	1,619,297		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 82

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
	Gas (Continued)		(Dollars)	
48	Total Operation and Maintenance			
49	Production—Manufactured Gas *(Enter Total of lines 28 and 40)*	316,957		
50	Production—Natural Gas (Including Expl. and Dev.) *(Total of lines 29 and 41)*			
51	Other Gas Supply *(Enter Total of lines 30 and 42)*			
52	Storage, LNG Terminaling and Processing *(Total of lines 31 and 43)*			
53	Transmission *(Enter Total of lines 32 and 44)*			
54	Distribution *(Enter Total of lines 33 and 45)*	4,046,366		
55	Customer Accounts *(Transcribe from line 34)*	1,572,379		
56	Customer Service and Informational *(Transcribe from line 35)*	40,724		
57	Sales *(Transcribe from line 36)*			
58	Administrative and General *(Enter Total of lines 37 and 46)*	2,042,373		
59	TOTAL Operation and Maint. *(Total of lines 49 thru 58)*	8,018,799	186,473	8,205,272
60	Other Utility Departments			
61	Operation and Maintenance			
62	TOTAL All Utility Dept. *(Total of lines 25, 59, and 61)*	217,170,516	4,867,759	222,038,275
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	61,395,419	4,453,061	65,848,480
66	Gas Plant	1,125,466	133,052	1,258,518
67	Other	960,060	2,116	962,176
68	TOTAL Construction *(Enter Total of lines 65 thru 67)*	63,480,945	4,588,229	68,069,174
69	Plant Removal (By Utility Department)			
70	Electric Plant	3,085,872	182,122	3,267,994
71	Gas Plant	127,233	9,427	136,660
72	Other	859		859
73	TOTAL Plant Removal *(Enter Total of lines 70 thru 72)*	3,213,964	191,549	3,405,513
74	Other Accounts *(Specify)*:			
75	Accounts receivable - Associated			
76	Companies	73,259		
77	Preliminary survey and investigation			
78	charges	974,427		
79	Research and development	1,220,567		
80	Miscellaneous suspense - debit	2,688,731		
81	Other income deductions	21,599		
82	Other work in progress	1,988,538		
83	Non-productive payroll	3,205,607		
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	10,172,728	932,401	11,105,129
96	TOTAL SALARIES AND WAGES	294,038,153	10,579,938	304,618,091

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors. (a)

2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used. (b)

3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation. (c)

4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization. (d)

(a) See page 356-A, 356-B, and 356-C
(b) See page 356-C
(c) See page 356-D
(d) April 19, 1941 - Docket No. IT-5718

COMMON UTILITY PLANT IN SERVICE (ACCOUNT 101 AND ACCOUNT 106)

	Account (a)	Balance beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance end of year (g)
	Intangible Plant						
301	Organization	$ 80,000	$	$	$	$ (80,000)	$
303	Miscellaneous Intangible Plant	545,267					545,267
	General Plant (1)						
389	Land and Land Rights	159,607				(159,607)	
390	Structures and Improvements	5,971,849	377,715			(5,634,359)	715,205
391	Office Furniture and Equipment	12,887,689	4,120,214		(38,889)	(908,581)	16,060,433
395	Laboratory Equipment (2)	27,475	28,292		46,755	(281)	102,241
397	Communication Equipment	476,169	26,475		8,360	(236,660)	274,344
398	Miscellaneous Equipment	529,634	74,953		(36,122)	(130,921)	437,544
	Total General Plant	20,052,423	4,627,649		(19,896)	(7,070,409)	17,589,767
	Total Common Utility Plant in Service	$20,677,690	$4,627,649	$	$ (19,896)	$(7,150,409)	$18,135,034

(1) Includes land, buidings, and furniture in Richmond, Virginia.

(2) Includes Laboratory equipment located in Richmond, Virginia.

CONSTRUCTION WORK IN PROGRESS - COMMON UTILITY (ACCOUNT 107)

Description of Project (a)	Balance end of Year (b)
Install a diagnostic system on data communications circuits provided by Communications Group at One James River Plaza	$ 20,507
Purchase software packages and develop computer programs for employees	189,035
Purchase software packages and develop computer programs for Purchasing Department	544,261
Purchase and install equipment for General Books System	1,143,957
Design and develop a computer system to convert an existing manual record asset accounting system to a modern EDP system	1,014,750
Construct a new garage entrance ramp	194,085
Purchase a stockholder records application software package for stockholder records	161,700
Install energy conservation system	19,238
Install public address system	92,833
Rewrite the Customer Accounting Billing System	19,957
Install a diesel fuel dispenser in garage	5,914
Install a restroom facility in the Medical Department	7,914
Replace lighting system in board room	8,317
Building Improvements $5,000 limit	12,559
Install V.H.F. Radio System	172,902
Peninsula District Headquarters Building	748
Virginia Beach Administration Building	554
Micro Computer Expansion Eastern Division	30,079
7th and Franklin Street security access/alarm	5,660
7th and Franklin Street customer lobby heating system	10,545
Virginia Beach District Office Telephone System	66,618
U.H.F. Radio System	12,095
Mount Storm Microwave Equipment	1,101
	$ 3,785,329

COMMON UTILITY PLANT AND ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION ALLOCABLE TO UTILITY DEPARTMENTS

Common Utility Plant in Service (Account 101 and Account 106)

	Account (a)	Total (b)	Electric (c)	Gas (d)
			ALLOCATION TO UTILITY DEPARTMENT	
	Intangible			
303	Miscellaneous Intangible Plant	$ 545,267	$ 534,362	$ 10,905
	General Plant			
390	Structures and Improvements	715,205	700,901	14,304
391	Office Furniture and Equipment	16,060,433	15,739,224	321,209
395	Laboratory Equipment	102,241	100,196	2,045
397	Communication Equipment	274,344	268,857	5,487
398	Miscellaneous Equipment	437,544	428,793	8,751
	Total General Plant	17,589,767	17,237,971	351,796
	Total Plant	$ 18,135,034	$ 17,772,333	$ 362,701

Accumulated Provision for Depreciation of Common Utility Plant in Service (Account 108 and 111)

A. Accumulated Provision Balances and Charges During Year

Item (a)	Total (b)
Balance beginning of year	$3,576,978
Depreciation accruals for year, charged to (403) Depreciation	1,128,000
Amortization accruals for year, charged to (404) Amortization	109,056
Net charges for plant retired:	
Book cost of plant retired	-0-
Cost of Removal	2,434
Salvage (Credit)	660
Net charges for plant retired	(1,774)
Other Debit or Credit Items (Described): Transfer of depreciation reserve for the 7th & Franklin Building, Richmond, Virginia, transferred from Non-utility to Plant in Service	520,786
Balance end of year	$5,333,046

B. Allocation of Accumulated Provision at End of Year by Departments

Electric	$5,226,385
Gas	106,661
Total	$5,333,046

Method of Allocation
Allocation is based on the ratio of use of 98% Electric and 2% Gas.

COMMON UTILITY PLANT EXPENSES

	Total Expenses for Year	Allocation to Utility Departments (a) Electric	Gas
Depreciation	$245,100	$210,450	$ 34,650
Taxes	233	220	13
Transmission:			
566 Miscellaneous transmission expenses	1,825	1,825	-
Distribution:			
586 Meter expenses	-	-	-
588 Miscellaneous distribution expenses	93,879	93,879	-
880 Other expenses	29,926	-	29,926
General:			
920 Administrative and general salaries	99,284	86,943	12,341
921 Office supplies and expenses	27,171	23,678	3,493
924 Property insurance	8,335	6,677	1,658
932 Maintenance of general plant	200,445	164,247	36,198
Total	$706,198(b)	$587,919	$118,279

(a) Allocated to departments on basis of use of each facility as follows:

	Electric	Gas
Richmond General Office Building	98%	2%

(b) Excludes $54,999 charged to Account 163, Stores Expenses Undistributed and $64,471 to Account 184, Clearing Accounts.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, and interchanged during the year.

Line No.	Item (a)	Megawatt Hours (b)	Line No.	Item (a)	Megawatt Hours (b)
1	SOURCES OF ENERGY		20	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		21	Sales to Ultimate Consumers (Including Interdepartmental Sales)	35,268,188
3	Steam	17,763,038			
4	Nuclear	17,420,492	22	Sales for Resale	4,712,059
5	Hydro—Conventional	679,381	23	Energy Furnished Without Charge	
6	Hydro—Pumped Storage		24	Energy Used by the Company (Excluding Station Use):	
7	Other	41,319			
8	Less Energy for Pumping		25	Electric Department Only *	373,224
9	Net Generation *(Enter Total of lines 3 thru 8)*	35,904,230	26	Energy Losses:	
			27	Transmission and Conversion Losses	
10	Purchases	3,305,661	28	Distribution Losses	Not
11	Interchanges:		29	Unaccounted for Losses	Separable
12	In (gross)	4,560,933	30	TOTAL Energy Losses	2,500,946
13	Out (gross)	952,433	31	Energy Losses as Percent of Total on Line 19 5.84 %	
14	Net Interchanges *(Lines 12 and 13)*	3,608,500			
15	Transmission for/by Others (Wheeling) (a)		32	TOTAL *(Enter Total of lines 21, 22, 23, 25, and 30)*	42,854,417
16	Received 1,067,464 MWh				
17	Delivered 1,031,438 MWh				
18	Net Transmission *(Lines 16 and 17)*	36,026			
19	TOTAL *(Enter Total of lines 9, 10, 14, and 18)*	42,854,417			

(a) See detail page 332&332-A

MONTHLY PEAKS AND OUTPUT

*Includes 2,313 MWhrs used in Gas Department.

1. Report below the information called for pertaining to simultaneous peaks established monthly (in megawatts) and monthly output (in megawatt-hours) for the combined sources of electric energy of respondent.

2. Report in column (b) the respondent's maximum MW load as measured by the sum of its coincidental net generation and purchases plus or minus net interchange, minus temporary deliveries (not interchange) of emergency power to another system. Show monthly peak *including* such emergency deliveries in a footnote and briefly explain the nature of the emergency. There may be cases of commingling of purchases and exchanges and "wheeling," also of direct deliveries by the supplier to customers of the reporting utility wherein segregation of MW demand for determination of peaks as specified by this report may be unavailable. In these cases, report peaks which include these intermingled transactions. Furnish an explanatory note which indicates, among other things, the relative significance of the deviation from basis otherwise applicable. If the individual MW amounts of such totals are needed for billing under separate rate schedules and are estimated, give the amount and basis of estimate.

3. State type of monthly peak reading (instantaneous 15, 30, or 60 minutes integrated).

4. Monthly output is the sum of respondent's net generation for load and purchases plus or minus net interchange and plus or minus net transmission or wheeling. Total for the year must agree with line 19 above.

5. If the respondent has two or more power systems not physically connected, furnish the information called for below for each system.

Name of System:

Line No.	Month (a)	MONTHLY PEAK Megawatts (b) (1)	Day of Week (c)	Day of Month (d)	Hour (e)	Type of Reading (f)	Monthly Output (MWh) (See Instr. 4) (g)
33	January	8,879	Monday	11	7-8A EST	60 Min. Int.	4,391,659
34	February	7,052	Friday	26	7-8A EST	60 Min. Int.	3,524,092
35	March	6,795	Monday	1	7-8A EST	60 Min. Int.	3,554,510
36	April	6,695	Wednesday	7	8-9A EST	60 Min. Int.	3,099,249
37	May	6,258	Monday	31	5-6P EDT	60 Min. Int.	3,194,750
38	June	7,325	Monday	28	5-6P EDT	60 Min. Int.	3,427,400
39	July	8,490	Monday	19	4-5P EDT	60 Min. Int.	4,139,069
40	August	7,947	Thursday	5	4-5P EDT	60 Min. Int.	3,395,107
41	September	7,089	Thursday	2	5-6P EDT	60 Min. Int.	3,293,777
42	October	5,820	Monday	25	10-11A EDT	60 Min. Int.	3,237,370
43	November	6,589	Tuesday	16	7-8A EST	60 Min. Int.	3,304,677
44	December	7,391	Tuesday	14	7-8A EST	60 Min. Int.	3,657,848
45	TOTAL						42,854,417 (2)

(1) and (2) See page 401-A

(1) MONTHLY PEAKS AND OUTPUT

Monthly peaks include cooperative customers of the Southeastern Power Administration located within the Virginia Electric and Power Company service area. The co-op loads, consisting of 184 delivery points, are so commingled with loads and deliveries of the Virginia Electric and Power Company that segregation for determination of the Company's hourly peaks is impossible. The monthly peak contract demand for the January 1, 1982 through December 29, 1982 period was 65,000 kW. As specified in the new SEPA contract effective December 30, 1982 the contract demand is 136,700 kW.

(2) The monthly output data in Column (g) excludes the following MWh adjustments:

January	28,135 MWh
February	30,521
March	10,363
April	10,822
May	10,056
June	10,901
July	11,813
August	10,870
September	10,694
October	144
November	590
December	--
Total	134,909 MWh

These adjustments resulted from a retroactive change in the method of accounting for interchange with cogenerators.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for Plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report on this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis, report the Btu content of the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (line 38) and average cost per unit of fuel burned (line 41) must be consistent with charges to expense accounts 501 and 547 (line 42) as shown on line 21.
8. If more than one fuel is burned in a plant, furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name Bremo (b)		Plant Name Chesterfield (c)		
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)	Steam		Steam		
2	Type of Plant Construction (Conventional, Outdoor Boiler, Full Outdoor, Etc.)	Conventional		Three Outdoor Boilers		
3	Year Originally Constructed	1931		1952		
4	Year Last Unit was Installed	1958		1969		
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	254		1,353		
6	Net Peak Demand on Plant—MW (60 minutes)	234		1,195		
7	Plant Hours Connected to Load	8,734		8,698		
8	Net Continuous Plant Capability (Megawatts)					
9	When Not Limited by Condenser Water Winter	228		1,280		
10	When Limited by Condenser Water Summer	221		1,250		
11	Average Number of Employees	118		420		
12	Net Generation, Exclusive of Plant Use — KWh	1,259,023,000		5,092,879,000		
13	Cost of Plant:					
14	Land and Land Rights	$ 93,144		$ 304,725		
15	Structures and Improvements	7,167,311		23,944,762		
16	Equipment Costs	33,108,344		201,054,791		
17	Total Cost	$ 40,368,799		$ 225,304,278		
18	Cost per KW of Installed Capacity (Line 5)	$ 159		$ 166		
19	Production Expenses:					
20	Operation Supervision and Engineering	$ 530,448		$ 2,839,641		
21	Fuel	28,033,793		108,703,935		
22	Coolants and Water (Nuclear Plants Only)					
23	Steam Expenses	566,298		2,231,4[illegible]		
24	Steam From Other Sources					
25	Steam Transferred (Cr.)					
26	Electric Expenses	323,847		869,417		
27	Misc. Steam (or Nuclear) Power Expenses	515,831		6,406,906		
28	Rents	7,202		53,047		
29	Maintenance Supervision and Engineering	285,549		1,721,058		
30	Maintenance of Structures	185,990		603,024		
31	Maintenance of Boiler (or Reactor) Plant	981,722		11,205,320		
32	Maintenance of Electric Plant	403,570		4,237,720		
33	Maint. of Misc. Steam (or Nuclear) Plant	290,403		2,801,819		
34	Total Production Expenses	$ 32,124,653		$ 141,724,398		
35	Expenses per Net KWh Mills	25.52		27.83		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Ign. Oil	Coal	Ign. Oil	#6 Oil
37	Unit: Coal—tons of 2,000 lb.)(Oil—barrels of 42 gals.)(Gas—Mcf)(Nuclear—indicate)	Tons	Bbls.	Tons	Bbls.	Bbls.
38	Quantity (Units) of Fuel Burned	543,859	8,980	2,024,232	117,965	51,473
39	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if nuclear)	12,363	139,941	12,572	140,903	150,225
40	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year $	50.64	39.11	43.13	40.[illegible]	--
41	Average Cost of Fuel per Unit Burned $	50.90	39.42	49.30	40.45	22.46
42	Avg. Cost of Fuel Burned per Million Btu $	2.058	6.707	1.961	6.879	3.560
43	Avg. Cost of Fuel Burned per KWh Net Gen.*	22.27 (a)		21.34 (a)		
44	Average Btu per KWh Net Generation	10,701 (a)		10,320 (a)		

See notes on Page 403-C.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U.S. of A. accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses classified as Other Power Supply Expenses.

10. For IC and GT plants, report Operating Expenses, Account Nos. 548 and 549 on line 26 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on line 32 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.

11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.

12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type, fuel used, fuel enrichment by type and quantity for the report period, and other physical and operating characteristics of plant.

Plant Name Mt. Storm (d)	Plant Name Portsmouth (e)	Plant Name Possum Point (f)	Line No.
Steam	Steam	Steam	1
Conventional	One Outdoor Boiler	Two Outdoor Boilers	2
1965	1953	1948	3
1973	1962	1975	4
1,662	650	1,373	5
1,581	388	1,092	6
8,555	7,725	8,389	7
			8
1,613	588	1,270	9
1,574	570	1,244	10
462	197	269	11
6,979,139,000	1,527,262,000	1,796,192,000	12
			13
$ 855,782	$ 193,746	$ 37,704	14
49,897,435	11,913,418	24,134,823	15
280,728,393	101,964,124	230,843,110	16
$ 331,481,610	$ 114,071,288	$ 255,015,637	17
$ 199	$ 175	$ 186	18
			19
$ 3,765,773	$ 865,196	$ 1,318,731	20
126,474,640	34,163,008	63,547,512	21
			22
1,165,891	999,567	1,038,964	23
			24
			25
960,419	772,873	729,559	26
6,037,693	1,169,377	1,281,690	27
97,496	92,701	35,326	28
2,422,605	667,642	972,446	29
1,367,821	156,046	185,370	30
20,234,755	2,998,927	3,671,904	31
6,323,790	814,907	2,633,105	32
5,716,793	527,295	894,096	33
$ 174,567,676	$ 43,227,539	$ 76,308,703	34
25.01	28.30	42.48	35

(d) Coal	(d) Ign. Oil	(e) Coal	(e) Ign. Oil	(e) #6 Oil	(f) Coal	(f) Ign. Oil	(f) #6 Oil	Line No.
Coal	Ign. Oil	Coal	Ign. Oil	#6 Oil	Coal	Ign. Oil	#6 Oil	36
Tons	Bbls.	Tons	Bbls.	Bbls.	Tons	Bbls.	Bbls.	37
3,106,795	179,552	576,715	12,745	169,780	536,846	16,820	1,111,902	38
11,675	140,002	12,756	139,887	147,127	12,518	139,967	147,190	39
37.27	40.44	49.18	41.04	--	49.50	40.58	30.98	40
38.29	41.90	50.66	38.17	26.24	51.25	41.84	31.77	41
1.640	7.126	1.986	6.497	4.247	2.047	7.147	5.140	42
18.12(a)		23.09(a)			35.74(a)			43
10,406(a)		10,554(a)			11,264(a)			44

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for Plant in Service only
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report on this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis, report the Btu content of the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (line 38) and average cost per unit of fuel burned (line 41) must be consistent with charges to expense accounts 501 and 547 (line 42) as shown on line 2".
8. If more than one fuel is burned in a plant, furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name Yorktown (b)		Plant Name Mt. Storm (c)	
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)	Steam		Combustion Turbine	
2	Type of Plant Construction (Conventional, Outdoor Boiler, Full Outdoor, Etc.)	Outdoor Boilers			
3	Year Originally Constructed	1957		1967	
4	Year Last Unit was Installed	1974		1967	
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	1,257		19	
6	Net Peak Demand on Plant—MW (60 minutes)	1,084		15	
7	Plant Hours Connected to Load	4,576		161	
8	Net Continuous Plant Capability (Megawatts)				
9	When Not Limited by Condenser Water Winter	1,166		16	
10	When Limited by Condenser Water Summer	1,154		12	
11	Average Number of Employees	218		(b)	
12	Net Generation, Exclusive of Plant Use — KWh	1,108,552,000		1,567,000	
13	Cost of Plant:				
14	Land and Land Rights	$ 1,390,049		$	
15	Structures and Improvements	34,511,616		61,044	
16	Equipment Costs	200,108,604		1,860,986	
17	Total Cost	$ 236,010,269		$ 1,922,030	
18	Cost per KW of Installed Capacity (Line 5)	$ 188		$ 101	
19	Production Expenses:				
20	Operation Supervision and Engineering	$ 782,940		$ 6,241	
21	Fuel	57,938,545		211,551	
22	Coolants and Water (Nuclear Plants Only)				
23	Steam Expenses	1,059,681			
24	Steam From Other Sources				
25	Steam Transferred (Cr.)				
26	Electric Expenses	609,110		14,373	
27	Misc. Steam (or Nuclear) Power Expenses	1,471,995			
28	Rents	88,808			
29	Maintenance Supervision and Engineering	825,080		1,430	
30	Maintenance of Structures	416,689		3,621	
31	Maintenance of Boiler (or Reactor) Plant	2,420,346			
32	Maintenance of Electric Plant	1,972,919		150,915	
33	Maint. of Misc. Steam (or Nuclear) Plant	1,574,741			
34	Total Production Expenses	$ 69,160,854		$ 388,131	
35	Expenses per Net KWh Mills	62.39		247.69	
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Ign. Oil	#6 Oil	Gas	Jet Oil
37	Unit: (Coal—tons of 2,000 lb.)(Oil—barrels of 42 gals.)(Gas—Mcf)(Nuclear—indicate)	Bbls.	Bbls.	Mcf	Bbls.
38	Quantity (Units) of Fuel Burned	12,013	1,613,110	2,847,156	4,849
39	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas)(Give unit if nuclear)	140,063	147,777	1,086	135,32[illegible]
40	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year $	41.35	26.43	4.39	42.24
41	Average Cost of Fuel per Unit Burned $	42.09	27.89	4.39	43.71
42	Avg. Cost of Fuel Burned per Million Btu $	7.156	4.493	4.036	7.691
43	Avg. Cost of Fuel Burned per KWh Net Gen.*	52.27(a)			135.00
44	Average Btu per KWh Net Generation	11,304(a)			17,551

See notes on Page 403-C.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1982

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U.S. of A. accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 548 and 549 on line 26 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on line 32 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development, (b) types of cost units used for the various components of fuel cost, and (c) any other informative data concerning plant type, fuel used, fuel enrichment by type and quantity for the report period, and other physical and operating characteristics of plant.

Plant Name Portsmouth* (d)		Plant Name Possum Point* (e)	Plant Name Surry* (f)		Line No.
Combustion Turbine		Combustion Turbine	Combustion Turbine		1
					2
1967		1968	1970		3
1969		1968	1970		4
163		96	40		5
135		102	41		6
254		121	122		7
					8
189		96	45		9
144		78	37		10
(b)		(b)	(b)		11
18,002,000		8,006,000	2,444,000		12
					13
$ 898		$	$		14
160,684		126,340			15
1,016,900		75,671	194,967		16
$ 1,178,482		$ 202,011	$ 194,967		17
$ --		$ --	$ --		18
					19
$ 119,880		$ 113,065	$ 13,475		20
1,520,116		930,908	209,074		21
					22
					23
					24
					25
85,294		47,394	18,850		26
					27
1,736,369		793,317	515,602		28
36,074		42,522	2,639		29
48,809		60,463	3,244		30
					31
746,074		365,459	153,110		32
					33
$ 4,292,616		$ 2,353,128	$ 915,994		34
238.45		293.92	374.79		35
Gas	Oil	Oil	Gas	Oil	36
Mcf	Bbls.	Bbls.	Mcf	Bbls.	37
259,860	11,304	23,712	40,759	913	38
1,030	139,976	140,007	1,038	139,676	39
4.16	38.77	39.23	4.26	27.56	40
4.16	38.85	39.26	4.26	39.03	41
4.039	6.608	6.676	4.100	6.653	42
84.44(a)		116.28	85.55(a)		43
18,547(a)		17,417	19,510(a)		44

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for Plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report on this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis, report the Btu content of the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (line 38) and average cost per unit of fuel burned (line 41) must be consistent with charges to expense accounts 501 and 547 (line 42) as shown on line 21.
8. If more than one fuel is burned in a plant, furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name Northern Neck* (b)	Plant Name Low Moor* (c)
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)	Combustion Turbine	Combuston Turbine
2	Type of Plant Construction (Conventional, Outdoor Boiler, Full Outdoor, Etc.)		
3	Year Originally Constructed	1971	1971
4	Year Last Unit was Installed	1971	1971
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	83	83
6	Net Peak Demand on Plant—MW (60 minutes)	73	80
7	Plant Hours Connected to Load	95	113
8	Net Continuous Plant Capability (Megawatts)		
9	When Not Limited by Condenser Water Winter	76	72
10	When Limited by Condenser Water Summer	64	62
11	Average Number of Employees	(c)	(c)
12	Net Generation, Exclusive of Plant Use — KWh	4,587,000	5,043,000
13	Cost of Plant:		
14	Land and Land Rights	$	$
15	Structures and Improvements		
16	Equipment Costs	62,538	40,678
17	Total Cost	$ 62,538	$ 40,678
18	Cost per KW of Installed Capacity (Line 5)	$ -	$ -
19	Production Expenses:		
20	Operation Supervision and Engineering	$ 18,390	$ 21,003
21	Fuel	540,330	605,763
22	Coolants and Water (Nuclear Plants Only)		
23	Steam Expenses		
24	Steam From Other Sources		
25	Steam Transferred (Cr.)		
26	Electric Expenses	14,506	16,085
27	Misc. Steam (or Nuclear) Power Expenses		
28	Rents	834,796	891,890
29	Maintenance Supervision and Engineering	29,636	34,212
30	Maintenance of Structures	11,401	5,978
31	Maintenance of Boiler (or Reactor) Plant		
32	Maintenance of Electric Plant	213,074	229,267
33	Maint. of Misc. Steam (or Nuclear) Plant		
34	Total Production Expenses	$1,662,133	$1,804,198
35	Expenses per Net KWh Mills	362.36	357.76
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Oil
37	Unit: (Coal—tons of 2,000 lb.)(Oil—barrels of 42 gals.)(Gas—Mcf)(Nuclear—indicate)	Bbls.	Bbls.
38	Quantity (Units) of Fuel Burned	13,026	14,218
39	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas)(Give unit if nuclear)	140,053	140,067
40	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year $	39.91	41.39
41	Average Cost of Fuel per Unit Burned $	41.48	42.61
42	Avg. Cost of Fuel Burned per Million Btu $	7.052	7.242
43	Avg. Cost of Fuel Burned per KWh Net Gen. *	117.80	120.12
44	Average Btu per KWh Net Generation	16,705	16,686

* Mills

See notes on Page 403-C.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U.S. of A. accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 548 and 549 on line 28 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on line 32 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type, fuel used, fuel enrichment by type and quantity for the report period, and other physical and operating characteristics of plant.

Plant Name Kitty Hawk* (d)	Plant Name Surry (e)	Plant Name North Anna (f)	Line No.
Combustion Turbine	Nuclear	Nuclear	1
			2
1971	1972	1978	3
1971	1973	1980	4
			5
48	1,695	1,959	
45	1,507	1,743	6
66	8,749	6,421	7
			8
56	1,550	1,759	9
44	1,550	1,755	10
(c)	578	595	11
1,670,000	10,975,433,000	6,445,059,000	12
			13
$ 20,159	$ 400,672	$ 36,343,868	14
	152,905,418	334,266,243	15
186,645	629,751,430	1,045,607,008	16
$ 206,804	$ 783,057,520	$ 1,416,217,119	17
$ --	$ 462	$ 723	18
			19
$ 14,602	$ 6,935,699	$ 5,175,608	20
217,777	70,494,811	35,755,474	21
	1,120,516	1,051,832	22
	1,328,406	4,689,186	23
		40	24
	986		25
78,121	709,807	1,029,370	26
	12,461,234	10,125,141	27
578,938	118,036	345,401	28
2,575	2,565,644	3,202,073	29
3,187	1,178,813	1,382,394	30
	2,959,026	9,641,790	31
162,067	2,897,241	4,322,677	32
	811,832	2,528,366	33
$ 1,057,267	$ 103,582,051	$ 79,249,352	34
633.09	9.44	12.30	35
Oil	Nuclear	Nuclear	36
			37
Bbls.	Grams Uranium 235	Grams Uranium 235	
6,222	1,118,924	601,925	38
			39
139,888	110,666(d)	118,448(d)	
			40
35.94	45.19	45.04	
35.00	63.00	59.40	41
5.957	.569	.502	42
130.41	6.42	5.55	43
19,246	11,282	11,062	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 82

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U.S. of A. accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 546 and 549 on line 28 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on line 32 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type, fuel used, fuel enrichment by type and quantity for the report period, and other physical and operating characteristics of plant.

Plant Name (d)	Plant Name (e)	Plant Name (f)	Line No.

Notes to Page 402 and 403:

(a) Composite rate for total fuel consumed.

(b) An average of 47 employees are assigned to combustion turbines maintenance.

(c) Remote unmanned station.

(d) Average heat content of fuel burned (1,000 BTU per gram uranium 235).

* Leased from United Virginia Bank and the Planters National Bank and Trust Company. Commission authorizations: State Corporation Commission of Virginia, Case No. A-117; North Carolina Utilities Commission, Docket No. E-22, Sub 125 and West Virginia Public Service Commission, Case No. 7248.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

Average Annual Heat Rates and Corresponding Net MWh Output for Most Efficient Generating Units

1. Report only the most efficient generating units (not to exceed 10 in number) which were operated at annual capacity factors of 50 percent or higher. List only unit type installations, i.e., single boiler serving one turbine-generator. It is not necessary to report single unit plants on this page. Do not include non-condensing or automatic extraction-type turbine units operated for processing steam and electric power generation.
2. Annual Unit Capacity Factor =

$$\frac{\text{Net Generation — Kwh:}}{\text{Unit KW. Capacity (as included in plant total — line 5, p. 402)} \times 8,760 \text{ hours}}$$

3. Report annual system heat rate for total conventional steam-power generation and corresponding net generation (line 11).
4. Compute all heat rates on this page and also on pages 403 and 404 on the basis of total fuel burned, including burner lighting and banking fuel.

Line No.	Plant Name (a)	Unit No. (b)	MW (Generator Rating at Maximum Hydrogen Pressure) (c)	Btu Per Net MWh x10^3 (d)	Net Generation Thousand MWh (e)	Kind of Fuel (f)
1	Bremo Bluff	4	185.277	10,030	950.548	Coal
2	Mount Storm	2	570.240	10,320	2,862.590	Coal
3	Surry	1	847.500	11,420	5,483.227	Uranium
4	Surry	2	847.500	11,150	5,492.206	Uranium
5						
6						
7						
8						
9						
10						
	Total System Steam Plants *					
11			6,549.330	10,558	17,763.038	

*Does not include nuclear units.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2009 Plant Name Roanoke Rapids (b)	FERC Licensed Project No. 2009 Plant Name Gaston (c)
1	Kind of Plant (Run-of-River or Storage)	Storage - Daily	Storage - Weekly
2	Type of Plant Construction (Conventional or Outdoor)	Semi-Outdoor	Outdoor
3	Year Originally Constructed	1955	1963
4	Year Last Unit was Installed	1955	1963
5	Total Installed Capacity (Generator Name Plate Ratings in MW)	100	178
6	Net Peak Demand on Plant—Megawatts (60 minutes)	101	228
7	Plant Hours Connected to Load	8,759	3,816
8	Net Plant Capability (In megawatts)		
9	(a) Under the Most Favorable Oper. Conditions	104	230
10	(b) Under the Most Adverse Oper. Conditions	100	225
11	Average Number of Employees	29	(a)
12	Net Generation, Exclusive of Plant Use — KWh	341,307,000	315,321,000
13	Cost of Plant:		
14	Land and Land Rights	$ 1,463,290	$ 7,730,323
15	Structures and Improvements	1,967,297	1,803,630
16	Reservoirs, Dams, and Waterways	20,601,984	24,252,869
17	Equipment Costs	6,527,812	10,185,535
18	Roads, Railroads, and Bridges	67,877	53,227
19	TOTAL Cost *(Enter Total of lines 14 thru 18)*	$ 30,628,260	$ 44,026,084
20	Cost per KW of Installed Capacity (Line 5)	$ 306	$ 247
21	Production Expenses:		
22	Operation Supervision and Engineering	$ 162,062	$ 177,322
23	Water for Power	33,908	1,181,0[illegible]
24	Hydraulic Expenses	18,196	150,534
25	Electric Expenses	109,793	93,416
26	Misc. Hydraulic Power Generation Expenses	68,103	34,379
27	Rents		
28	Maintenance Supervision and Engineering	168,740	145,495
29	Maintenance of Structures	55,342	34,960
30	Maintenance of Reservoirs, Dams, and Waterways	26,407	11,630
31	Maintenance of Electric Plant	365,123	68,239
32	Maintenance of Misc. Hydraulic Plant	48,735	42,403
33	Total Production Expenses *(Total lines 22 thru 32)*	$ 1,061,403	$ 1,939,219
34	Expenses per Net KWh Mills	3.11	6.15

(a) Supervisory control from Roanoke Rapids.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. ______ Plant Name ______ (d)	FERC Licensed Project No. ______ Plant Name ______ (e)	FERC Licensed Project No. ______ Plant Name ______ (f)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
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			32
			33
			34

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. ____ Plant Name ____ (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	None
3	Year Last Unit was Installed	
4	Total Installed Capacity (Generator Name Plate Ratings in MW)	
5	Net Peak Demand on Plant—Megawatts (60 minutes)	
6	Plant Hours Connected to Load While Generating	
7	Net Plant Capability (In megawatts):	
8	Average Number of Employees	
9	Generation Exclusive of Plant Use – KWh	
10	Energy Used for Pumping – KWh	
11	Net Output for Load (line 9 minus line 10) – KWh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	TOTAL Cost *(Enter Total of lines 13 thru 19)*	
21	Cost per KW of Installed Capacity *(line 20 ÷ line 4)*	
22	Production Expenses	
23	Operation Supervision and Engineering	
24	Water for Power	
25	Pumped Storage Expenses	
26	Electric Expenses	
27	Miscellaneous Pumped Storage Power Generation Expenses	
28	Rents	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Reservoirs, Dams, and Waterways	
32	Maintenance of Electric Plant	
33	Maintenance of Miscellaneous Pumped Storage Plant	
34	Production Exp. Before Pumping Exp. *(Enter Total of lines 23 thru 33)*	
35	Pumping Expenses	
36	Total Production Expenses *(Enter Total of lines 34 and 35)*	
37	Expenses per KWh *(Enter result of line 36 divided by line 9)*	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (line 10) is that energy measured as input to the plant for pumping purposes.

7. Include on line 35 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed, leave lines 35, 36 and 37 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other sources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier, contract number, and date of contract.

FERC Licensed Project No. ____ Plant Name ____ (c)	FERC Licensed Project No. ____ Plant Name ____ (d)	FERC Licensed Project No. ____ Plant Name ____ (e)	Line No.
			1
			2
			3
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see Instruction 11, page 403.
4. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity-Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 Min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost per KW Inst. Capacity (g)	Production Expenses: Operation Exc'l. Fuel (h)	Production Expenses: Fuel (i)	Production Expenses: Maintenance (j)	Kind of Fuel (k)	Fuel Cost (In cents per million Btu) (l)
1												
2	Hydro				Kwh							
3												
4	Cushaw	1930	7.5	6.0*	22,753,000	$1,185,898	$158	$53,666		$61,422		
5												
6												
7												
8												
9	* Estimated from 24 hours integration.											
10												
11												
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

CHANGES MADE OR SCHEDULED TO BE MADE IN GENERATING PLANT CAPACITIES

Give below the information called for concerning changes in electric generating plant capacities during the year.

A. Generating Plants or Units Dismantled, Removed from Service, Sold, or Leased to Others During Year

1. State in column (b) whether dismantled, removed from service, sold, or leased to another. Plants removed from service include those not maintained for regular or emergency service.
2. In column (f), give date dismantled, removed from service, sold, or leased to another. Designate complete plants as such.

Line No.	Name of Plant (a)	Disposition (b)	Installed Capacity (In megawatts) Hydro (c)	Steam (d)	(Other) (e)	Date (f)	If Sold or Leased to Another, Give Name and Address of Purchaser or Lessee (g)
1							
2							
3							
4							
5							
6							
7							

B. Generating Units Scheduled for or Undergoing Major Modifications

Line No.	Name of Plant (a)	Character of Modification (b)	Installed Plant Capacity After Modification (In megawatts) (c)	Estimated Dates of Construction Start (d)	Completion (e)
8	Chesterfield #3	Conv. to Coal-fired oper.	112.5	1-17-84	4-10-84
9	Yorktown #1	Conv. to Coal-fired oper.	187.5	3-07-84	5-31-84
10	Yorktown #2	Conv. to Coal-fired oper.	187.5	8-22-84	12-12-84
11	Portsmouth #1	Conv. to Coal-fired oper.	112.5	1985	1-01-86
12	Portsmouth #2	Conv. to Coal-fired oper.	112.5	1985	1-01-86
13	Possum Pt. #1	Conv. to Coal-fired oper.	69.0	1985	1-01-86
14	Possum Pt. #2	Conv. to Coal-fired oper.	69.0	1985	1-01-86

C. New Generating Plants Scheduled for or Under Construction

Line No.	Plant Name and Location (a)	Type (Hydro, Pumped Storage, Steam, Internal Combustion, Gas-Turbine, Nuclear, etc.) (b)	Installed Capacity (In megawatts) Initial (c)	Ultimate (d)	Estimated Dates of Construction Start (e)	Completion (f)
15	Bath Co. #1,2,4, Bath Co,Va	Pumped Storage	525		Spring 77	10-01-85
16	Bath Co. #3,5,6, Bath Co,Va	Pumped Storage	525		Spring 77	10-01-86
17						
18						
19						
20						
21						

D. New Units in Existing Plants Scheduled for or Under Construction

Line No.	Plant Name and Location (a)	Type (Hydro, Pumped Storage, Steam, Internal Combustion, Gas-Turbine, Nuclear, etc.) (b)	Unit No. (c)	Size of Unit (In megawatts) (d)	Estimated Dates of Construction Start (e)	Completion (f)
22						
23						
24						
25						
26						
27						
28						

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

STEAM-ELECTRIC GENERATING PLANTS

1. Include on this page steam-electric plants of 25,000 Kw (name plate rating) or more of installed capacity.
2. Report the information called for concerning generating plants and equipment at end of year. Show unit type installation, boiler, and turbine-generator, on same line.
3. Exclude plant, the book cost of which is included in Account 121, *Nonutility Property*.
4. Designate any generating plant or portion thereof for which the respondent is not the sole owner. If such property is leased from another company give name of lessor, date and term of lease, and annual rent. For any generating plant, other than a leased plant or portion thereof for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) as to such matters as percent ownership by respondent, name of co-owner, basis of sharing

Line No.	Name of Plant	Location of Plant	Boilers *(Include both ratings for the boiler and the turbine-generator of dual-rated installations)*				
			Number and Year Installed	Kind of Fuel and Method of Firing	Rated Pressure (in psig)	Rated Steam Temperature *(Indicate reheat boilers as 1050/1000)*	Rated Max. Continuous M lbs. Steam per Hour
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Bremo	Bremo Bluff, Va.	1 - 1958	Coal - Pulv.	2,450	1,000/1,000	1,170
2	Bremo	Bremo Bluff, Va.	1 - 1950	Coal - Pulv.	1,300	950	625
3	Chesterfield	Nr. Chester, Va.	1 - 1969	Oil/Coal - Pulv.	2,630	1,000/1,000	4,620
4	Chesterfield	Nr. Chester, Va.	1 - 1964	Oil/Coal - Pulv.	2,620	1,000/1,000	2,305
5	Chesterfield	Nr. Chester, Va.	1 - 1960	Oil/Coal - Pulv.	2,603	1,000/1,000	1,200
6	Chesterfield	Nr. Chester, Va.	1 - 1952	Oil/Coal - Pulv.	1,500	1,000/1,000	750
7	Mt. Storm	Mt. Storm, W. Va.	1 - 1973	Coal - Pulv.	2,620	1,000/1,000	3,826
8	Mt. Storm	Mt. Storm, W. Va.	1 - 1966	Coal - Pulv.	2,620	1,000/1,000	3,785
9							
10	Mt. Storm	Mt. Storm, W. Va.	1 - 1965	Coal - Pulv.	2,620	1,000/1,000	3,785
11							
12	Portsmouth	Chesapeake, Va.	1 - 1962	Oil/Coal - Pulv.	2,620	1,000/1,000	1,620
13	Portsmouth	Chesapeake, Va.	1 - 1959	Oil/Coal - Pulv.	2,450	1,000/1,000	1,170
14	Portsmouth	Chesapeake, Va.	1 - 1954	Oil/Coal - Pulv.	1,500	1,000/1,000	750
15	Portsmouth	Chesapeake, Va.	1 - 1953	Oil/Coal - Pulv.	1,500	1,000/1,000	750
16	Possum Point	Nr. Dumfries, Va.	1 - 1975	Oil	2,600	1,000/1,000	5,841
17	Possum Point	Nr. Dumfries, Va.	1 - 1962	Oil/Coal - Pulv.	2,600	1,000/1,000	1,620
18	Possum Point	Nr. Dumfries, Va.	1 - 1955	Oil/Coal - Pulv.	1,500	1,000/1,000	750
19	Possum Point	Nr. Dumfries, Va.	1 - 1951	Oil/Coal - Pulv.	875	900	650
20	Possum Point	Nr. Dumfries, Va.	1 - 1948	Oil/Coal - Pulv.	875	900	650
21	Yorktown	Nr. Yorktown, Va.	1 - 1974	Oil	2,600	1,000/1,000	5,841
22	Yorktown	Nr. Yorktown, Va.	1 - 1958	Oil/Coal-Pulv./Gas	2,000	1,000/1,000	1,200
23	Yorktown	Nr. Yorktown, Va.	1 - 1957	Oil/Coal Pulv. Gas	2,000	1,000/1,000	1,200
24	Surry	Nr. Surry, Va.	Not Applicable - (Nuclear Unit)				
25	Surry	Nr. Surry, Va.	Not Applicable - (Nuclear Unit)				
26	North Anna	Nr. Mineral, Va.	Not Applicable - (Nuclear Unit)				
27	North Anna	Nr. Mineral, Va.	Not Applicable - (Nuclear Unit)				
28							
29							
30							
31							
32							
33							

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

STEAM-ELECTRIC GENERATING PLANTS (Continued)

output, expenses or revenues, and how expenses and/or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.

5. Designate any generating plant or portion thereof leased to another company and give name of lessee, date and term of lease and annual rent, and how determined. Specify whether lessee is an associated company.

6. Designate any plant or equipment owned, not operated, and not leased to another company. If such plant or equipment was not operated within the past year explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost are contemplated.

7. Report gas-turbines operated in a combined cycle with a conventional steam unit with its associated steam unit.

Turbine-Generators

(Report cross-compound turbine-generator units on two lines – H.P. section and I.P. section. Designate units with shaft connected boiler feed pumps. Give capacity rating of pumps in terms of full load requirements)

Year Installed (h)	Turbines: Max. Rating Mega-watt (i)	Turbines: Type (Indicate tandem-compound (TC); cross-compound (CC), single casing (SC), topping unit (T), and noncondensing (NC). Show back pressures) (j)	Turbines: Steam Pressure at Throttle psig. (k)	Turbines: RPM (l)	Generators: Name Plate Rating in Megawatts: At Minimum Hydrogen Pressure (m)	Generators: Name Plate Rating in Megawatts: At Maximum Hydrogen Pressure (Include both ratings for the boiler and the turbine-generator of dual-rated installations) (n)	Hydrogen Pressure (Designate air cooled generators): Min (o)	Hydrogen Pressure: Max. (p)	Power Factor (q)	Voltage (In KV) (If other than 3 phase, 60 cycle, indicate other characteristic) (r)	Plant Capacity, Maximum Generator Name Plate Rating (Should agree with column (n)) (s)	Line No
1958	175.	T.C. 1.5"	2,200	3,600	148 221	185 277	30	60	0.85	18 0		1
1950	66.	T.C. 1.5"	1,250	3,600	60.000	69 000	0.5	15	0.85	13 8	254 277	2
1969(A)	634.	T.C. 3.5"	2,401	3,600	187 353	693.900	0.5	60	0.90	24 0		3
1964(B)	344.	T.C. 1.5"	2,520	3,600	326 400	359 040	30	45	0.85	22.0		4
1960	159.	T.C. 1.5"	2,400	3,600	170 455	187 500	30	45	0.85	22 0		5
1952	99.	T.C. 1.5"	1,450	3,600	90 000	112 500	0.5	30	0.85	14 4	1.352 940	6
1973	519.	T.C. 2.5"	2,400	3,600	–	522 000	–	60	0.90	24 0		7
1966(C)	565.	C.C. 2.0"	2,520	HP 3,600	225 392	285 120	30	60	0.90	22 0		8
				LP 3,600	225 392	285 120	30	60				9
1965(C)	565.	C.C. 2.0"	2,520	HP 3,600	225.392	285 120	30	60	0.90	22 0		10
				LP 3,600	225 392	285 120	30	60			1.662.480	11
1962	200.	T.C. 3.5"	2,400	3,600	189 218	239 360	30	60	0.85	20 0		12
1959	150.	T.C. 1.5"	2,200	3,600	148 221	185 277	30	60	0.85	18 0		13
1954	99.	T.C. 1.5"	1,450	3,600	90 000	112.500	0.5	30	0.85	14 4		14
1953	99.	T.C. 1.5"	1,450	3,600	90.000	112.500	0.5	30	0.85	14 4	649 637	15
1975	792.	T.C. 3.5"	2,400	3,600	590 940	882.000	30	75	0.90	25 0		16
1962	213.	T.C. 1.5"	2,400	3,600	217 600	239 360	30	45	0.85	22.0		17
1955	100.	T.C. 1.5"	1,450	3,600	100 000	113 636	0.5	30	0.85	14 4		18
1951	66.	T.C. 1.5"	850	3,600	60 000	69 000	0.5	15	0.85	13 8		19
1948	66.	T.C. 1.5"	850	3,600	60.000	69.000	0.5	15	0.85	13 8	1.372 996	20
1974	816.	T.C. 2.0"	2,400	3,600	590 940	882 000	30	75	0.90	25 0		21
1958	150.	T.C. 1.5"	1,800	3,600	170 455	187 500	30	45	0.85	18 0		22
1957	150.	T.C. 1.5"	1,800	3,600	170 455	187 500	30	45	0.85	22 0	1.257 000	23
1973	823.	T.C. 1.5"	733.3	1,800	–	847 530	–	60	0.90	22.0		24
1972	823.	T.C. 1.5"	733.3	1,800	–	847 530	–	60	0.90	22 0	1.695 060	25
1980	943.	T.C. 1.5"	803	1,800	–	979 740	–	60	0.90	22.0		26
1978	943.	T.C. 1.5"	803	1,800	–	979 740	–	60	0.90	22 0	1.959 480	27
												28
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												31
												32
												33

Notes

(A) Shaft driven BFP - 16.539 KW

(B) Shaft driven BFP - 7.251 KW

(C) Two Shaft driven BFP - 6.274 KW each

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

HYDROELECTRIC GENERATING PLANTS

1. Report on this page Hydro plants of 10,000 Kw (name plate rating) or more of installed capacity.
2. Report the information called for concerning generating plants and equipment at end of year. Show associated prime movers and generators on the same line.
3. Exclude from this schedule, plant, the book cost of which is included in Account 121, *Nonutility Property*.
4. Designate any plant or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and term of lease, and annual rent. For any generating plant, other than a leased plant, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving

Line No.	Name of Plant (a)	Location (b)	Name of Stream (c)	Water Wheels (In column (e), indicate whether horizontal or vertical. Also indicate type of runner — Francis (F), fixed propeller (FP), automatically adjustable propeller (AP), impulse (I). Designate reversible type units by appropriate footnote): Attended or Unattended (d)	Type of Unit (e)	Year Installed (f)	Gross Static Head With Pond Full (g)
1							
2	Gaston	Roanoke Rapids	Roanoke River	Unattended	1-V-AP	1963	63.0
3	(1)	N.C.	" "	"	3-V-FP	1963	63.0
4							
5	Roanoke Rapids	Roanoke Rapids,					
6	(1)	N.C.	Roanoke River	Attended	2V-AP	1955	76.0
7					2F-AP		
8							
9							
10							
11							
12							
13							
14							
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16							
17	(1) Licensed Project No. 2009.						
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

HYDROELECTRIC GENERATING PLANTS (Continued)

particulars (details) as to such matters as percent ownership by respondent, name of co-owner, basis of sharing output, expenses, or revenues, and how expenses and/or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.

5. Designate any plant or portion thereof leased to another company, and give name of lessee, date and term of lease and annual rent, and how determined. Specify whether lessee is an associated company.

6. Designate any plant or equipment owned, not operated, and not leased to another company. If such plant or equipment was not operated within the past year explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost are contemplated.

Water Wheels (Continued)			Generators						Total Installed Generating Capacity (Name Plate Ratings) (In megawatts)	Line No.
Design Head (h)	RPM (i)	Maximum Hp. Capacity of Unit at Design Head (j)	Year Installed (k)	Voltage (l)	Phase (m)	Frequency or d.c. (n)	Name Plate Rating of Unit (In megawatts) (o)	Number of Units in Plant (p)	(q)	
										1
67	100	77,000	1963	14,400	3	60	44.480	3		2
67	100	70,000	1963	14,400	3	60	44.480	1	177.920	3
										4
										5
74.5	128.5	35,000	1955	14,400	3	60	25.020	4	100.080	6
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

PUMPED STORAGE GENERATING PLANTS

1. Include in this schedule pumped storage plants of 10,000 Kw (name-plate rating) or more of installed capacity.

2. Report the information called for concerning generating plants and equipment at end of year. Show associated prime movers and generators on the same line.

3. Exclude from this schedule the book cost of plant included in Account 121, *Nonutility Property*.

4. Designate any plant or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and term of lease, and annual

Line No.	Name of Plant (a)	Location (b)	Name of Stream (c)	WATER WHEELS OF HYDRAULIC TURBINES PUMPS *(In column (e), indicate whether horizontal or vertical or inclined. Also indicate type of runner — Francis (F), fixed propeller (FP), automatically adjustable propeller (AP), impulse (I), or Tublar (T). Designate reversible type units by appropriate footnote)* — Attended or Unattended (d)	Type of Unit (e)	Year Installed (f)	Gross Static Head with Pond Full (g)	Design Head (h)
1								
2			None					
3								
4								
5								
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

PUMPED STORAGE GENERATING PLANTS (Continued)

rent. For any generating plant, other than a leased plant, or portion thereof, for which the respondent shares in the operation of, furnish a concise statement explaining the arrangement and giving particulars as to such matters as percent ownership by respondent, name of co-owner, basis of sharing output, expenses, or revenues, and how expenses and or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.

SEPARATE MOTOR-DRIVEN PUMPS

RPM (Designate whether turbine or pump) (i)	Maximum Hp Capacity of Unit at Design Head (j)	Year Installed (k)	Type (l)	RPM (m)	Phase (n)	Frequency or dc (o)	NAME PLATE RATING IN Hp (p)	NAME PLATE RATING IN MVa (q)	Line No
		None							1
									2
									3
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

PUMPED STORAGE GENERATING PLANTS (Continued)

5. Designate any plant or portion thereof leased to another company and give name of lessee, date and term of lease and annual rent and how determined. Specify whether lessee is an associated company.

6. Designate any plant or equipment owned, not operated, and not leased to another company. If such plant or equipment was not operated within the past year, explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost are contemplated.

Line No.	GENERATORS OR GENERATOR/MOTORS (In column (v), designate whether generator or motor) Year Installed (r)	Voltage (s)	Phase (t)	Frequency or d.c (u)	Name Plate Rating of Unit (In megawatts) (Designate whether MVa, MW, or Hp, indicate power factor) (v)	Number of Units in Plant (w)	Total Installed Generating Capacity (Name Plate Ratings) (In megawatts) (x)
1							
2					None		
3							
4							
5							
6							
7							
8							
9							
10							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

INTERNAL-COMBUSTION ENGINE AND GAS TURBINE GENERATING PLANTS

1. Include on this page internal-combustion engine and gas-turbine plants of 10,000 kilowatts and more.
2. Report the information called for concerning plants and equipment at end of year. Show associated prime movers and generators on the same line.
3. Exclude from this page, plant, the book cost of which is included in Account 121, *Nonutility Property*.
4. Designate any plants or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and term of lease, and annual rent. For any generating plant other than a leased plant, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) as to such matters as percent of ownership by respondent, name of co-owner, basis of sharing output, expenses, or revenues, and how expenses and/or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.

Line No.	Name of Plant (a)	Location of Plant (b)	Prime Movers (In column (e), indicate basic cycle for gas-turbine as open or closed; indicate basic cycle for internal combustion as 2 or 4): Interal-Combustion or Gas-Turbine (c)	Year Installed (d)	Cycle (e)	Belted or Direct Connected (f)
1	Mt. Storm	Mt. Storm, W. Va.	Gas Turbine	1967	Open	Direct
2						
3	Portsmouth	Chesapeake, Va.	Gas Turbine	1967	Open	Direct
4	"	"	"	1969	Open	Direct
5	"	"	"	1969	Open	Direct
6	"	"	"	1970	Open	Direct
7						
8	Possum Point	Dumfries, Va.	Gas Turbine	1968	Open	Direct
9						
10	Surry	Surry, Va.	Gas Turbine	1970	Open	Direct
11	"	"	"	1970	Open	Direct
12						
13	Kitty Hawk	Kitty Hawk, N.C.	Gas Turbine	1971	Open	Direct
14						
15	Northern Neck	Warsaw, Va.	Gas Turbine	1971	Open	Direct
16						
17	Lowmoor	Lowmoor, Va.	Gas Turbine	1971	Open	Direct
18						
19						
20						
21						
22	Instruction 4 - See note designated by * on page 402-C					
23						
24						
25						
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

INTERNAL-COMBUSTION ENGINE AND GAS-TURBINE GENERATING PLANTS (Continued)

5. Designate any plant or portion thereof leased to another company and give name of lessee, date and term of lease and annual rent, and how determined. Specify whether lessee is an associated company.

6. Designate any plant or equipment owned, not operated, and not leased to another company. If such plant or equipment was not operated within the past year, explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost are contemplated.

Prime Movers (Continued)	Generators						Total Installed Generating Capacity (Name plate ratings) (In megawatts)	Line No.
Rated Hp of Unit (g)	Year Installed (h)	Voltage (i)	Phase (j)	Frequency or d.c. (k)	Name Plate Rating of Unit (In megawatts) (l)	Number of Units in Plant (m)	(n)	
N/A	1967	13,800	3	60	18.594	1	18.594	1
								2
N/A	1967	13,800	3	60	18.594	1		3
N/A	1969	13,800	3	60	16.320	3		4
N/A	1969	13,800	3	60	23.800	2		5
N/A	1970	13,800	3	60	23.800	2	162.754	6
								7
N/A	1968	13,800	3	60	16.000	6	96.000	8
								9
N/A	1970	13,800	3	60	16.320	1		10
N/A	1970	13,800	3	60	23.800	1	40.120	11
								12
								13
N/A	1971	13,800	3	60	23.800	2	47,600	14
								15
N/A	1971	13,800	3	60	20.700	4	82.800	16
								17
N/A	1971	13,800	3	60	20.700	4	82.800	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
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								40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, *Nonutility Property*.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole, wood, or steel; (2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	Code No.	DESIGNATION		VOLTAGE (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole Miles) (In the case of underground lines, report circuit miles)		Number of Circuits
		From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structures of Line Designated (f)	On Structures of Another Line (g)	(h)
1	531	Surry	Yadkin	500	500	Steel Tower	50.43		1
2	549	Valley	Dooms	500	500	Steel Tower	17.72		1
3	550	Mt. Storm	Valley	500	500	Steel Tower	64.24		1
4	551	Mt. Storm	Doubs	500	500	Steel Tower	96.14		1
5	552	Ox	Ladysmith	500	500	Steel Tower	59.73		1
6	553	Dooms	Elmont	500	500	Steel Tower	82.21		1
7	554	Mt. Storm	Pruntytown	500	500	Steel Tower	5.72		1
8	555	Dooms	Cloverdale	500	500	Steel Tower	46.40		1
9	557	Elmont	Surry	500	500	Steel Tower	72.17		1
10	558	Loudoun	Doubs	500	500	Steel Tower	16.22		1
11	559	Loudoun	Ox	500	500	Steel Tower	19.20		1
12	562	Surry	Carson	500	500	Steel Tower	49.88		1
13	563	Carson	Midlothian	500	500	Steel Tower	37.03		1
14	569	Loudoun	Morrisville	500	500	(Steel Tower	8.10		1
15						(Steel Tower	21.20		1
16	570	Carson	Wake	500	500	Steel Tower	56.39		1
17	572	Morrisville	Mt. Storm	500	500	Steel Tower	47.35		1
18	573	North Arna	Morrisville	500	500	Steel Tower	32.89		1
19	574	Elmont	Ladysmith	500	500	Steel Tower	26.19		1
20	575	North Arna	Ladysmith	500	500	(Steel Tower	13.52		1
21						(H. Frame Steel	1.01		1
22	576	Midlothian	North Anna	500	500	Steel Tower	41.16		1
23							864.90		
24									
25									
26									
27	200	Ox	Bull Run	230	230	(Steel Tower		17.36	1
28						(H. Frame Steel	2.93		3
29						(Steel Pole	3.91		2
30									
31									
32									
33									
34									
35									
36						TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 82

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2500 MCM ACAR	$ 1,207,708	$ 6,211,302	$ 7,419,010	$	$	$	$	1
2049 MCM ALUM	Cost	Included in No	550					2
2049 MCM ALUM	959,007	7,653,919	8,612,926					3
2049 MCM ALUM	1,247,733	9,716,321	10,964,054					4
2049 MCM ALUM	2,032,676	6,490,729	8,523,405					5
2049 MCM ALUM	1,139,017	6,978,096	8,117,113					6
32 MCM ACSR	58,369	612,811	671,180					7
2049 MCM ALUM	581,439	3,313,484	3,894,923					8
2500 MCM ACAR	1,604,423	11,287,187	12,891,610					9
2049 MCM ALUM	677,789	1,354,677	2,032,466					10
2500 MCM ACAR	504,110	2,347,525	2,851,635					11
2500 MCM ACAR	879,084	5,755,583	6,634,667					12
2500 MCM ACAR	4,046,315	10,300,501	14,346,816					13
2500 MCM ACAR)	2,255,462	2,965,865	5,221,327					14
2500 MCM ALUM)								15
2500 MCM ACAR	962,744	5,523,947	6,486,691					16
2500 MCM ACAR	5,130,603	11,532,702	16,663,305					17
2500 MCM ACAR	2,781,273	4,413,823	7,195,096					18
2049 MCM ALUM	459,959	2,529,255	2,989,214					19
2500 MCM ACAR)	636,058	2,939,550	3,575,608					20
2454 MCM SDC)								21
2500 MCM ACAR	3,445,497	7,054,843	10,500,340					22
	30,609,266	108,982,120	139,591,386	544,050	908,822	48,003	1,500,875	23
								24
								25
								26
1033 MCM ACSR)	1,876,134	4,042,380	5,918,514					27
2500 MCM AA)								28
2500 MCM AA)								29
								30
								31
								32
								33
								34
								35
								36

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, *Nonutility Property*.

5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole, wood, or steel; (2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	Code No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole Miles) (In the case of underground lines, report circuit miles) On Structures of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)
1	201	Pleasant View	Loudoun	230	230	Steel Tower	12.99		1
2	202	Idylwood	Clark	230	230	Steel Tower	22.63		1
3	203	Pleasant View	Dickerson	230	230	Steel Tower	3.00		1
4	204	Gum Springs	Jefferson St.	230	230(	Steel Tower	6.14		1
5					(	Steel Tower	4.41		1
6	205	Chesterfield	Locks	230	230)	Steel Tower	12.22		1
7					)	Wood Pole	.01		1
8	206	Idylwood	Braddock	230	230	Steel Tower	4.77		1
9	207	Braddock	Ox	230	230	Steel Tower	7.76		1
10	208	Chesterfield	Southwest	230	230(	Steel Tower	10.39		1
11					(	Steel Tower	3.74		1
12	209	Lanexa	Yorktown	230	230)	Wood	28.70		1
13					)	Steel Tower	4.21		1
14	210	Jefferson St.	Van Dorn	230	230	Steel Tower		2.90	1
15	211	Chesterfield	Hopewell	230	230	Steel Tower	11.13		1
16	212	Hopewell	Surry	230	230)	H. Frame Steel	.21		1
17					)	Steel Tower	42.76	55.45	1
18	213	Carolina	Thelma	230	230	Steel Tower	10.33		1
19	214	Surry	Whealton	230	230(	Steel Tower	14.10		1
20					(	Steel Tower		23.38	1
21	215	Possum Point	Hayfield	230	230)	Steel Tower	12.44		1
22					)	Steel Tower	7.62		1
23	216	Lakeside	Elmont	230	230	Steel Tower	5.80		1
24	217	Lakeside	Chesterfield	230	230(	H. Frame Wood	20.27		1
25					(	Steel Tower	.47	.63	1
26	218	Everetts	Greenville	230	230)	H. Frame Wood	20.36		1
27					)	Steel Tower	1.84		1
28	219	Midlothian	Southwest	230	230	Steel Pole	5.38	.67	1
29	220	Ox	Gum Springs	230	230(	Steel Tower		2.40	1
30					(	Wood Pole		2.02	1
31									
32									
33									
34									
35									
36						TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1033 MCM ACSR	$ 19,948	$ 737,340	$ 757,288	$	$	$	$	1
1192 MCM ACSR	670,771	2,012,415	2,683,186					2
1177 MCM ALUM		271,180	271,180					3
3 MCM ACAR)	94,020	363,191	457,211					4
9 MCM ALUM)								5
1033 MCM ALUM(	205,338	2,938,820	3,144,158					6
795 MCM ALUM(								7
795 MCM ACSR		433,084	433,084					8
295 MCM ACSR		838,987	838,987					9
1033 MCM ALUM(	Cost included in 21	9.						10
1109 MCM ACAR(								11
1033 MCM ACSR)	160,382	1,561,338	1,721,720					12
721 MCM ACAR)								13
1109 MCM ACSR		294,716	294,716					14
1109 AR 23/13	113,860	812,205	926,065					15
2500 AR 84/17)	1,246,089	4,231,949	5,478,038					16
721 AR 18/19)								17
1033MCM ACSR	130,355	228,789	359,144					18
1534 MCM ACAR(	202,261	5,072,712	5,274,973					19
1033 MCM ACSR(								20
721 MCM ACSR)	989,712	2,715,428	3,705,140					21
2500 MCM ACAR)								22
2500 MCM ACAR	11,401	1,531,265	1,542,666					23
795 MCM ACSR)	353,220	94,161	447,381					24
)								25
1109 MCM ACAR(	306,385	605,501	911,886					26
(								27
721 MCM ACAR	92,207	559,255	651,462					28
1109 MCM ACAR)	734,462	293,449	1,027,911					29
)								30
								31
								32
								33
								34
								35
								36

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, *Nonutility Property*.

5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole, wood, or steel; (2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	Code No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole Miles) (In the case of underground lines, report circuit miles) On Structures of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number of Circuits (h)
1	221	Northwest	Elmont	230	230	Steel Tower	5.82		1
2	222	Chesterfield	Southwest	230	230	Steel Tower	10.18		1
3	223	Surry	Greenwich	230	230)	Steel Tower	10.23		1
4					)	Steel Tower	30.31	16.67	1
5	224	Possum Point	Ox	230	230(	Wood Pole	.27		1
6					(	Steel Pole		14.03	1
7	225	Lakeview	Thelma	230	230	Steel Tower	9.33		1
8	226	Surry	Churchland	230	230(	Steel Tower		37.42	1
9					(	Steel Pole		.11	1
10	228	Chesterfield	Hopewell	230	230	Steel Tower		11.23	1
11	229	Everetts	Rocky Mount	230	230)	Steel Tower		4.14	1
12					)	Steel Tower	2.52		1
13					)	H. Fr. Wood	42.55		1
14									
15	232	Gaston	Thelma	230	230	Steel Tower	.17		1
16	235	Halifax	Farmville	230	230(	Steel Tower	4.20		1
17					(	H. Fr. Wood	61.12		1
18	236	Southwest	Plaza	230	230)	Steel Pole	3.30		1
19					)	Steel Pole	.74		1
20	237	Possum Point	Idylwood	230	230	Steel Tower	14.03		1
21	239	Lakeview	Rocky Mount	230	230(	Wood	32.29		1
22					(	Steel Tower		4.14	1
23	240	Hopewell	Surry	230	230	Steel Tower		42.97	1
24	241	Jefferson St.	Hayfield	230	230	Steel Tower	6.26		1
25	242	Loudoun	Pleasant View	230	230	Steel Tower		12.99	1
26	243	Ox	Hayfield	230	230)	Steel Pole	8.29		1
27					)	Wood Pole	.11		1
28									
29									
30									
31									
32									
33									
34									
35									
36						TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

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9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
721 MCM ACAR	$ 16,399	$ 738,038	$ 745,437	$	$	$	$	1
1033 MCM ACSR	43,544	1,062,513	1,106,057					2
1109 MCM ACAR(	1,295,990	4,763,215	6,059,205					3
721 MCM ACAR(								4
1033 MCM ACSR)		268,537	268,537					5
)								6
MCM ACSR	62,507	342,492	404,999					7
721 MCM ACAR)		1,702,711	1,702,711					8
2500 MCM ACAR)								9
1109 MCM ACAR		190,806	190,806					10
1109 MCM ACAR(	483,174	1,249,051	1,732,225					11
1033 MCM ACSR(								12
(								13
								14
1033 MCM ACSR	Cost included in No. 225.							15
545 MCM ACAR)	1,612,318	4,437,805	6,050,123					16
)								17
2500 MCM ACAR(	1,142,056	1,264,615	2,406,671					18
721 MCM ACAR(								19
795 MCM ACSR	107,311	1,070,456	1,177,767					20
1033 MCM ACSR)	279,741	1,273,694	1,553,435					21
1109 MCM ACAR)								22
721 MCM AR		645,561	645,561					23
1033 MCM ACSR		599,731	599,731					24
2500 MCM ACAR	892	198,308	199,200					25
477 MCM ACSR(	132,880	2,160,021	2,292,901					26
(								27
								28
								29
								30
								31
								32
								33
								34
								35
								36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, *Nonutility Property.*
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole, wood, or steel; (2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	Code No.	DESIGNATION		VOLTAGE (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole Miles) (In the case of underground lines, report circuit miles)		Number of Circuits
		From	To	Operating	Designed		On Structures of Line Designated	On Structures of Another Line	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	246	Suffolk	Earleys	230	230)	H. Fr. Wood	41.03		1
2					)	Steel Tower	3.10		1
3	247	Suffolk	Winfall	230	230	H. Fr. Wood	35.36		1
4	248	Glebe	Hayfield	230	230(	Steel Pole	9.55		1
5					(	Steel Pole		8.22	2
6	249	Locks	Carson	230	230)	H. Fr. Wood	6.69		1
7					)	Steel Tower		3.64	1
8	250	Arlington	Jefferson St.	230	230	Steel Pole		6.85	1
9	251	Arlington	Idylwood	230	230(	Concrete Pole	.09		1
10					(	Steel Pole		6.33	1
11					(	H. Fr. Wood		1.31	1
12	252	Possum Point	Fredericksburg	230	230	Steel Tower	13.39	11.31	1
13	253	Valley	Harrisonburg	230	230	Steel Tower	10.79		1
14	254	Clubhouse	Lakeview	230	230	H. Fr. Wood	18.03		1
15	256	Elmont	Fredericksburg	230	230	H. Fr. Wood	34.11		1
16	257	Churchland	Sewells Point	230	230)	Steel Pole	5.22		1
17					)	Submarine	1.59		1
18	258	Arlington	Glebe	230	230	Steel Pole	2.49		1
19	259	Basin	Chesterfield	230	230(	H. Fr. Wood	.59		1
20					(	Steel Tower	3.25	3.83	1
21					(	Steel Pole	4.62		1
22	260	Grottoes	Harrisonburg	230	230	H. Fr. Wood	10.80		1
23	261	Newport News	Shellbank	230	230	Steel Pole	4.88		1
24	262	Yadkin	Greenwich	230	230)	Steel Tower	13.75		1
25					)	H. Fr. Wood	.10		1
26	263	Chuckatuck	Newport News	230	230(	Steel Pole	.09		1
27					(	Steel Tower	.78	15.53	1
28	266	Loudoun	Glen Carlyn	230	230)	Steel Tower	19.06		1
29					)	Steel Pole		12.21	1
30					)	Steel Pole		5.17	1
31									
32									
33									
34									
35									
36						TOTAL			

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
545 MCM ACAR(	$1,451,639	$1,927,009	$3,378,648	$	$	$	$	1
(								2
1109 MCM ACAR	187,298	796,536	983,834					3
795 MCM ACSR)	37,617	2,625,922	2,663,539					4
2500 MCM ACAR)								5
721 MCM ACAR(		122,806	122,806					6
MCM ACSR(								7
MCM ACAR	261,563	839,776	1,101,339					8
1600 MCM AA)		2,008,968	2,008,968					9
)								10
1109 MCM ACAR)								11
795 MCM ACSR	144,990	5,549,196	5,694,186					12
721 MCM ACAR	430,940	1,836,005	2,266,945					13
795 MCM ACSR								14
795 MCM ACSR	344,479	1,003,752	1,348,231					15
721 MCM ACAR(	252,620	4,058,159	4,310,779					16
1500 Copper (								17
2500 MCM ACAR	121,784	792,969	914,753					18
1109 MCM ACAR)	33,989	1,495,119	1,529,108					19
636 MCM ACSR)								20
2500 MCM ACAR)								21
1109 MCM ACAR	27,895	592,915	620,810					22
1109 MCM ACAR	120,741	787,907	908,648					23
1109 MCM ACAR(	103,362	76,508	179,870					24
1033 MCM ACAR(								25
1109 MCM ACAR)	31,608	79,882	111,490					26
1534 MCM ACAR)								27
1033 MCM ACSR(	339,280	2,358,196	2,697,476					28
2500 MCM ACAR(								29
1600 MCM ALUM(								30
								31
								32
								33
								34
								35
								36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, *Nonutility Property*.

5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole, wood, or steel; (2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	Code No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole Miles) (In the case of underground lines, report circuit miles) On Structures of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number of Circuits (h)
1	267	Churchland	Yadkin	230	230(	Steel Tower	6.88	2.30	1
2					(	Steel Pole		.11	1
3	268	Yadkin	Fentress	230	230)	Wood Pole	.40		1
4					)	Steel Tower	7.38		1
5					)	Steel Pole	5.94		1
6	269	Shawboro	Fentress	230	230(	Steel Tower	4.32		1
7					(	H. Fr. Wood	20.91		1
8	271	Fentress	Lynnhaven	230	230)	Steel Tower	14.96		1
9					)	Concrete Pole	1.85		1
10	272	Dooms	Grottoes	230	230	Steel Tower	11.33		1
11	273	Glen Carlyn	Arlington	230	230	Steel Tower		2.42	1
12	275	Glebe	Crystal	230	230	Underground	1.23		1
13	276	Glebe	Crystal	230	230	Underground	1.20		1
14	282	Basin	Midlothian	230	230(	Steel Tower	16.06		1
15					(	Steel Tower		8.29	1
16	283	Elmont	Northeast	230	230)	Steel Tower	5.21		1
17					)	H. Fr. Wood	7.99		1
18	284	Basin	Northeast	230	230(	Steel Tower	6.27		1
19					(	H. Fr. Wood	2.26		1
20	285	Lanexa	Chesterfield	230	230	H. Fr. Wood	28.98		1
21	286	Northeast	Lanexa	230	230	Steel Tower	31.97		1
22	288	Yorktown	Shellbank	230	230)	Wood Pole	3.08		1
23					)	Steel Tower		7.70	1
24					)	Steel Pole		6.34	1
25	289	Suffolk	Chuckatuck	230	230(	H. Fr. Wood	.13		1
26					(	Steel Tower	9.85	4.31	1
27					(	3-Pole Angle	.27		1
28	290	Surry	Chuckatuck	230	230)	Steel Tower		22.92	1
29					)	Wood Pole		.10	1
30									
31									
32									
33									
34									
35									
36						TOTAL			

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way): Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES: Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
721 MCM ACAR)	$	$ 404,434	$ 404,434	$	$	$	$	1
2500 MCM ACAR)								2
2500 MCM ACAR(	2,658,857	6,060,847	8,719,704					3
(								4
(								5
5 MCM ACAR)	473,885	1,163,955	1,637,840					6
545 MCM ACAR)								7
721 MCM ACAR(	925	360,587	361,512					8
2500 MCM ACAR(								9
721 MCM ACAR		250,403	250,403					10
1600 AA/61	297,819	70,860	368,679					11
1750 Copper	1,560	1,214,693	1,216,253					12
1750 Copper	Cost included in No.	275						13
721 MCM ACAR)	53,900	2,329,898	2,383,798					14
636 MCM ACSR)								15
721 MCM ACAR(		1,330,602	1,330,602					16
(								17
721 MCM ACAR)	68,731	618,305	687,036					18
)								19
1033 MCM ACSR	883,080	6,416,070	7,299,150					20
721 MCM ACAR	55	3,321,661	3,321,716					21
721 MCM ACAR)	2,897	2,877,260	2,880,157					22
)								23
)								24
2500 MCM ACAR(	227,396	1,886,783	2,114,179					25
721 MCM ACAR(								26
(								27
721 MCM ACAR)	2,414		2,414					28
)								29
								30
								31
								32
								33
								34
								35
								36

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, *Nonutility Property*.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole, wood, or steel; (2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	Code No.	DESIGNATION		VOLTAGE (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole Miles) (In the case of underground lines, report circuit miles)		Number of Circuits
		From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structures of Line Designated (f)	On Structures of Another Line (g)	(h)
1	292	Whealton	Yorktown	230	230(	Steel Tower	10.51		1
2					(	H. Fr. Wood	3.82		1
3	293	Valley	Dooms	230	230	H. Fr. Wood	17.28	7.80	1
4	295	Loudoun	Bull Run	230	230	Steel Tower		8.56	1
5	296	Halifax	Roxboro	230	230	H. Fr. Wood	20.45		1
6	298	Charlottesville	Farmville	230	230(	H. Fr. Wood	25.49		1
7					(	H. Fr. Concrete	28.31		1
8	2001	Ox	Possum Point	230	230)	Wood Pole	.17		1
9					)	Steel Tower		12.23	1
10					)	Steel Pole		1.31	1
11	2002	Carson	Poe	230	230(	Wd 3 Pole angle	.25		1
12					(	Steel Tower	1.10	4.60	1
13					(	H. Fr. Concrete	7.00		1
14	2003	Chesterfield	Poe	230	230)	Steel Pole	.19		1
15					)	Steel Tower	7.34		1
16					)	Steel Tower		2.53	2
17					)	Steel Tower		9.40	2
18	2007	Thalia	Lynnhaven	230	230	Concrete Pole	3.31		1
19	2012	Carolina	Earleys	230	230(	Steel Tower	5.50		2
20					(	H. Fr. Steel		32.07	2
21	2014	Earleys	Everetts	230	230	H. Fr. Wood	31.64	.26	1
22	2016	Lanexa	Harmony Village	230	230)	Steel Tower	4.06		1
23					)	H. Fr. Steel	25.69		1
24	2019	Greenwich	Thalia	230	230	Concrete Pole	2.32		1
25	2032	Bear Island	Elmont	230	230	H. Fr. Wood	8.79		1
26	2034	Earleys	Trowbridge	230	230(	H. Fr. Wood	28.40		1
27					(	Steel Tower	5.53		1
28	2035	Idylwood	CIA	230	230	Concrete Pole	6.28		1
29	2039	Morrisville	Remington	230	230	Steel Tower	4.80		1
30							1,198.30	456.06	
31									
32									
33									
34									
35									
36						TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1982

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1033 MCM ACSR(	$	$ 164,619	$ 164,619	$	$	$	$	1
721 MCM ACAR(								2
545 MCM ACAR	36,539	1,160,689	1,197,228					3
1033 MCM ACSR	200,440	499,674	700,114					4
-45 MCM ACAR	385,497	753,260	1,138,757					5
. MCM ACAR(	149,960	3,145,041	3,295,001					6
545 MCM ACAR(								7
2500 MCM ACAR)	100,689	267,768	368,457					8
721 MCM ACAR)								9
2500 MCM ACAR)								10
721 MCM ACAR(								11
(								12
(	Costs included in No. 205.							13
2500 MCM ACAR)	52,371		52,371					14
721 MCM ACAR)								15
1109 MCM ACAR)								16
1033 MCM ACSR)								17
2500 MCM ACAR		111,423	111,423					18
545 MCM ACAR(	79,518	2,851,620	2,931,138					19
(								20
545 MCM ACAR		1,269,091	1,269,091					21
1033 MCM SSAC)	215,8 0	3,707,552	3,923,422					22
)								23
2500 MCM ACAR		200,098	200,098					24
795 MCM ACSR	Cost included in No. 256.							25
545 MCM ACAR(	1,503,362	3,848,049	5,351,411					26
(								27
1033 MCM SSAC	Costs not classified as in service.							28
545 MCM ACAR	674,902	628,286	1,303,188					29
	24,343,829	125,470,872	149,814,701	754,821	1,283,210	66,599	2,104,630	30
								31
								32
								33
								34
								35
								36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, *Nonutility Property*.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole, wood, or steel; (2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	Code No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole Miles) (In the case of underground lines, report circuit miles) On Structures of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)
1	8	Bremo	Clifford APCO	138	138	Steel Tower	7.30		1
2	12	Lexington	Clifton Forge	138	138	Steel Tower	23.77	10.16	1
3	14	Hinton APCO	Covington	138	138(	Steel Tower	51.38		1
4					(	Wood Pole	1.79		1
5	112	Covington	Lowmoor	138	138	Steel Tower	5.39	.65	1
6	133	Clifton Forge	Lowmoor	138	138	Steel Tower	5.05		1
7	155	Covington	Westvaco	138	138)	Steel Tower	1.35		1
8					)	Wood Pole	1.79		1
9							97.82	10.81	
10									
11									
12		Various	Various	115	115(	Steel Tower			
13					(	H. Fr. Wood			
14					(	Wood Poles			1
15							2,487.63	377.32	
16									
17									
18		Various	Various	69	69(	H. Fr. Wood			
19					(	Wood Poles			
20							99.95		
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32									
33									
34									
35									
36						TOTAL	4,688.60	844.19	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 82

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
397 MCM ACSR	$ 39,730	$ 226,417	$ 266,147	$	$	$	$	1
4/0 ACSR	55,246	960,548	1,015,794					2
4/0 ACSR(	170,736	1,098,840	1,269,576					3
396 MCM ACAR(								4
4/0 MCM ACSR	33,315	299,537	332,852					5
109 MCM ACAR	10,187	77,538	87,725					6
/0 ACSR)								7
396 MCM ACAR)								8
	309,214	2,662,880	2,972,094	61,401	96,659	5,418	163,478	9
								10
								11
								12
								13
Various								14
	33,135,831	126,876,931	160,012,762	1,529,125	3,106,386	134,918	4,770,429	15
								16
								17
								18
Various								19
	365,081	1,506,047	1,871,128	62,582	83,170	5,522	151,274	20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	88,763,221	365,498,850	464,262,071	2,951,979	5,478,247	260,460	8,690,686	36

FERC FORM NO. 1 (REVISED 12-82)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.

2. Provide separate subheadings for overhead and underground construction and show each transmission line separately. If actual costs of completed construction are not readily available for reporting in columns (l) to (o), it is permissible to report in these columns the estimated final completion costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION Code No.	From (a)	To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	Average Number per Mile (e)	CIRCUITS PER STRUCTURE Present (f)	Ultimate (g)	CONDUCTORS Size (h)	Specification (i)	Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST (Dollars) (A) Land and Land Rights (l)	Poles, Towers, and Fixtures (m)	Conductors and Devices (n)	Total (o)
1	59	Tap Point	Short Pump	6.51	Wood "H" Fr.	7	1	1	1,109	ACAR	H 18'10"	115	902,298	716,201	259,234	1,877,733(B)
2	81	Tap Point	Consol. Diesel	1.22	Wood Pole	14	1	1	336	ACSR	Variable	115	74,219	107,410	60,136	241,765(B)
3	84	Tap Point	South Creek	12.41	Wood Pole	10	1	1	545	ACAR	Variable	115	559,373	641,786	379,154	1,580,313(B)
4	230	Greenville	CP&L	(12.95)	Wood "H" Fr.	8	1	1	545	ACAR	H 19'0"	230	(7,250)	(883,569)	(444,452)	(1,335,271)(C)
5	244	Twr. No. 12	Str. No. 49	(4.29)	Wood "H" Fr.	9	1	1	1,109	ACAR	H 17'10"	230)				
6	244	Str. No. 49	Twr. No. 51	(.30)	Steel Tower	6	1	2	1,109	ACAR	V 15'&17'	230)	(167,736)	(182,040)	(110,960)	(460,736)(C)
7	244	Twr. No. 51	CP&L	(2.45)	Wood "H" Fr.	9	1	1	1,109	ACAR	H 17'10"	230)				
8	244	Greenville	Twr. No. 12	(1.83)	Steel Tower	7	2	2	1,109	ACAR	V 15'&17'	230)				
9	82	Str. No.1717	Str. No. 1727	(1.25)	Wood "H" Fr.	7	1	1	336	ACSR	H 17'6"	115 (	(78,600)	(58,284)	(24,066)	(160,950)(C)
10	82	Str. No.1727	Greenville	(.63)	Steel Tower	5	1	1	545	ACAR	V 15'&17'	115 (				
11																
12																
13		(A)	Lines 1-10 include the following respective amounts for clearing costs in column (l):													
14			1. $100,694													
15			2. $ 35,283													
16			3. $128,566													
17			4. $ (6,154)													
18			5.) 6.) 7.) 8.) $(75,375)													
19																
20			9.(10.($(22,753)													
21		(B)	Estimated final completion cost.													
22		(C)	Facilities sold to Carolina Power and Light Company.													
23		( )	Denotes red figure.													
24																
25																
26																
27																
28			TOTAL	(3.56)									1,282,304	341,504	119,046	1,742,854

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	*See Above Character of Substation # (b)	VOLTAGE - KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	CENTRAL DIVISION										
2	Chippenham District-Virginia										
3	Basin-Richmond)		230	34.5Y		168.	2				
4	)		115	13.2Y		22.4	1				
5	Bellwood-Chesterfield Co.		115	13.2Y		32.5	2				
6	Centralia-Chesterfield Co.		115	13.2Y		34.9	2				
7	Dupont-Chesterfield Co.		115	13.2Y		80.	3				
8	Hull Street-Chesterfield Co.		230	34.5Y		134.4	3				
9	"K"-Richmond		13.2	4.16Y		3.75	1				
10	Manchester-Richmond)		115	13.2Y		100.	2	1-40.000			
11	)		34.5	13.2Y				1-20.000			
12	)		13.2	4.16Y		7.5	3	1- 1.150			
13	Maury Street-Richmond		115	13.2Y		5.	1				
14	McGuire-Richmond		13.2	4.16Y		1.725	1				
15	Midlothian-Chesterfield Co.		115	34.5Y		22.4	1				
16	Midlothian-Chesterfield Co.		230	34.5Y		45.	1				
17	Pike-Chesterfield Co.		13.2	4.16Y		1.5	3				
18	Plaza-Richmond		115	13.2Y		42.4	2				
19	Plaza		230	34.5Y		56.	1				
20	Powhatan-Powhatan Co.		115	34.5Y		22.4	1				
21	"Q"-Richmond)		34.5	13.2Y		20.	1				
22	)		13.2	4.16Y		5.	3	1- 1.667			
23											
24											
25											

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation # (b)	VOLTAGE- KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	Chippenham Dist. (Cont.)										
2	Southwest-Chesterfield Co.		230	34.5Y		224.	2				
3	Stratford Hills-Chesterfield Co.		115	13.2Y		44.8	2				
4	Ironbridge-Chesterfield Co.		230	34.5Y		45.	1				
5											
6											
7	Pole Stations										
8	Chesterfield Co.)	(1)	7.6	19.9		.333	1				
9	)	(35)	19.9	7.6		12.33	41				
10	City of Richmond)	(38)	19.9	7.6		15.	46				
11	)	(2)	7.6	19.9		.834	4				
12	)	(3)	19.9	2.4		.667	3				
13	)	(1)	7.6	2.4		.167	1				
14	Powhatan Co.	(15)	19.9	7.6		8.098	21				
15											
16	Pad Stations										
17	Chesterfield Co.	(1)	34.5	13.2		5.	2				
18	City of Richmond)	(1)	7.6	19.9		.333	1				
19	)	(2)	19.9	7.6		1.166	3				
20	Powhatan Co.	(1)	7.6	19.9		.333	1				
21											
22											
23											
24											
25											

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation # (b)	VOLTAGE – KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	CENTRAL DIVISION										
2	Gloucester District-Virginia										
3	Cooks Corner-Middlesex Co.		34.5	12.5Y		2.5	1				
4	Deltaville-Middlesex Co.		34.5	12.5Y		6.25	1				
5	Gloucester-Gloucester Co.		34.5	12.5Y		6.75	4				
6	Harmony Village-Middlesex Co.		115	34.5Y		20.	1				
7	Hayes-Gloucester Co.		115	34.5Y		22.4	1				
8	Martino-King & Queen Co.		34.5	12.5Y		2.	1				
9	Mathews-Mathews Co.		34.5	12.5Y		7.5	1				
10	Mattaponi-King William Co.		34.5	4.16Y		2.	3	1- .500			
11	Shacklefords-King & Queen Co.		115	34.5Y		20.	1				
12	Wan-Gloucester Co.		115	34.5Y		56.	3	1-18.67			
13	West Point-King William Co.)		115	34.5Y		22.4	1				
14	)		115Y	13.2		12.5	1				
15	White Ship-King William Co.		34.5	13.2Y		3.45	3	1- .333			
16											
17	Pole Stations										
18	Gloucester Co.)	(3)	7.2	19.9		.501	3				
19	)	(30)	19.9/7.2			13.827	38				
20	King & Queen Co.)	(1)	34.5Y/12.5Y	AUTO		.334	2				
21	)	(2)	19.9/7.6	AUTO		.500	2				
22	)	(1)	19.9	7.2		.333	1				
23	King William Co.	(1)	19.9	7.6		.333	1				
24	Mathews Co.	(17)	19.9/7.2			10.165	26				
25	Middlesex Co.	(13)	19.9/7.2	AUTO		6.832	20				

FERC FORM NO. 1 (REVISED 12-81)

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1	Gloucester District (Cont.)										
2	Town of West Point	(1)	34.5Y	4.16Y		.999	3				
3											
4											
5											
6											
7											
8											
9											
10											
11											
12											
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

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Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation # (b)	VOLTAGE- KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	Central Division										
2	Northern Neck District - Virginia										
3	Callao-Northumberland Co.		34.5	12.5Y		4.687	1				
4	Dunnsville-Essex Co.		115	34.5Y		22.4	1				
5	Garner-Richmond Co.		115	34.5Y		12.5	1				
6	Lancaster-Lancaster Co.)		115	34.5Y		22.4	1				
7	)		115	12.5Y		20.	1				
8	Lilian-Northumberland Co.		34.5	12.5Y		3.75	3				
9	Montross-Westmoreland Co.		34.5	12.5Y		4.2	1				
10	Northern Neck-Richmond Co.		115	34.5Y		22.4	1				
11	Tappahannock-Tappahannock		34.5	4.16Y		3.125	1				
12	Warsaw-Richmond Co.		34.5Y	12.5		8.9	1				
13	Sanders-Westmoreland Co.		115	34.5Y		12.5	1				
14	White Stone-Whitestone		115Y	12.5		12.5	1				
15											
16	Pole Stations										
17	Essex Co.)	(1)	34.5	13.2		.999	3				
18	)	(3)	19.9	7.6		1.	3				
19	King & Queen Co.	(3)	19.9	7.6		.467	3				
20	Lancaster Co.)	(2)	34.5	12.5		1.998	6				
21	)	(1)	19.9	7.2		.333	1				
22	Northumberland Co.)	(3)	34.5	12.5		2.499	9				
23	)	(9)	19.9	7.2		3.832	11				
24	Richmond Co.	(3)	19.9	7.2		.999	3				
25											

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation ø (b)	VOLTAGE - KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	Northern Neck Dist.-Virginia Cont.										
2	Westmoreland Co.)	(3)	34.5	12.5		2.668	9				
3	)	(5)	19.9	7.2		2.832	7				
4											
5											
6											
7											
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25											

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

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Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation # (b)	VOLTAGE - KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	CENTRAL DIVISION										
2	Petersburg District-Virginia										
3	Allied-Chesterfield Co.		115	13.2Y		64.8	3				
4	Battersea-Petersburg		13.2	4.16		1.5	1				
5	Battlefield-Hopewell		34.5	13.2Y		12.5	1				
6	City Point-Hopewell		13.2	4.16Y		2.0	1				
7	Colonial Heights-Col. Hghts.		13.2	4.16Y		5.249	1				
8	Dinwiddie-Dinwiddie Co.		34.5	13.2Y		4.68	1				
9	Disputanta-Prince George Co.		115	13.2Y		14.	1				
10	Enon - Chesterfield Co.		115	13.2Y		22.4	1				
11	Fort Lee-Prince George Co.		115	13.2Y		42.4	2				
12	Garysville-Prince George Co.		34.5	13.2Y		12.5	1				
13	Harrowgate-Chesterfield Co.		115	13.2Y		44.8	2				
14	Harvell-Petersburg)		115	13.2Y		73.6	2				
15	)		13.2	4.16Y		10.	2				
16	Hopewell-Hopewell)		230Y	34.5Y	13.2	111.	1				
17	)		230/36.5Y	AUTO	13.2	112.	1				
18	)		230	34.5		168.	1				
19	)		34.5	13.2Y		80.	2				
20	)		13.2	4.16Y		3.75	1				
21	)		13.2	4.16Y							
22	Jarratt-Greensville Co.)		115	13.2Y		5.6	1				
23	)		115	13.2D		21.331	6	1-4.444			
24											

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 82

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Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation ø (b)	VOLTAGE – KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	Petersburg District (Cont.)										
2	Locks-Petersburg)		115	34.5Y		40.0	1				
3	)		115	13.2Y		33.6	1				
4	)		115Y	13.2Y		20.	1				
5	)		13.2	4.16Y		2.	1				
6	McKenny-Dinwiddie Co.		34.5	13.2Y		3.5	1				
7	Poe-Petersburg)		115Y	34.5		75.	1				
8	)		115	13.2Y		40.	2				
9	)		34.5	13.2Y		20.	1				
10	Prince George Co.		34.5	13.2Y		12.5	1				
11	Saint Andrews-Petersburg		13.2	4.16Y		5.	1				
12	Sapony-Sussex Co.		115	34.5Y		22.4	1				
13	Stony Creek-Sussex Co.		34.5	13.2Y		3.5	1				
14	Tyler-Chesterfield Co.)		230	34.5Y		44.8	1				
15	)		115	13.2Y		20.	1				
16	)		34.5	13.2				1-22.400			
17	Wakefield-Sussex Co.)		115	34.5Y		12.5	1				
18	)		115Y	12.5		6.	3	1- 2.000			
19	)		13.2	4.16Y		3.125	1	1- 1.250			
20	Walnut Hill-Petersburg		13.2	4.16Y		3.	3	1- 1.200			
21	Waverly-Sussex Co.		115	12.5Y		12.5	1				
22											
23											
24											
25											

FERC FORM NO. 1 (REVISED 12-81)

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

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Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation ϕ (b)	VOLTAGE – KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	Petersburg District Cont.										
2	Pole Stations										
3	Chesterfield Co.)	(2)	34.5	13.2		1.998	6				
4	)	(1)	7.6	19.9		.666	2				
5	)	(2)	13.2	34.5		1.998	6				
6	)	(7)	19.9	7.6		2.333	7				
7	City of Hopewell)	(1)	34.5	4.16		.999	3				
8	)	(1)	13.2	4.16		.999	3				
9	City of Petersburg)	(1)	19.9	7.6		.666	2				
10	)	(1)	34.5	4.16		.999	3				
11	)	(3)	19.9	2.4		.999	3				
12	Dinwiddie Co.	(1)	34.5	13.2		.833	3				
13	Prince George Co.)	(4)	34.5	13.2		4.664	12				
14	)	(6)	19.9	7.6		1.999	6				
15	Sussex Co.	(7)	19.9	7.6		2.168	7				
16											
17											
18	Pad Stations										
19	Chesterfield Co.	(2)	13.2	34.5		5.	2				
20	Prince George Co.	(1)	34.5	13.2		2.5	1				
21											
22											
23											
24											
25											

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

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Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation ∅ (b)	VOLTAGE - KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	CENTRAL DIVISION										
2	Richmond District-Virginia										
3	Acca-Henrico Co.)		115	34.5Y		150.	2				
4	)		115	13.2Y		40.	1				
5	)		115Y	13.2		40.	1				
6	Belt Line-Richmond		34.5	4.16Y		5.6	1				
7	Carver City-Richmond)		115	13.2Y		80.	2				
8	)		115Y	13.2		40.	1				
9	)		115/34.5Y	AUTO	13.2	50.	1				
10	Dumbarton-Henrico Co.		34.5Y	4.16Y		2.5	3				
11	Elmont-Hanover Co.)		230Y	34.5Y	13.2	56.	1				
12	)		230	34.5Y		45.	1				
13	Hollywood D.P.		13.2	4.2		3.	3				
14	First Street-Richmond		13.2	4.16Y		6.25	1				
15	Ginter Park-Henrico Co.		13.2	4.16Y		3.75	1				
16	Grove Avenue-Richmond)		34.5	13.2		14.	1				
17	)		34.5	4.16Y		8.15	1				
18	Hanover-Hanover Co.		115	13.2Y		20.	1				
19	Horsepen-Henrico Co.		34.5	4.16Y		5.6	1				
20	Laburnum-Henrico Co.		34.5Y	4.16Y		5.	3				
21	Lakeside-Henrico Co.)		230	13.2Y		56.	1				
22	)		230	34.5Y		168.	2				
23	Maidens-Goochland Co.		34.5	13.2Y		6.25	1				
24	Myers Street-Richmond		13.2	4.16Y		3.75	1				
25											

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1982

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1	Richmond District Cont.										
2	North Doswell-Hanover Co.		115	13.2		22.4	1				
3	Northwest-Henrico Co.		230	34.5Y		224.	2				
4	Orchid-Louisa Co.		34.5	12.5Y		4.311	3				
5	Reservoir-Richmond		34.5	4.16Y		14.4	2				
6	River Road-Henrico Co.)		115	34.5Y		50.	1				
7	)		230	34.5Y		84.	1				
8	)		115	13.2Y		42.4	2				
9	Shockoe-Richmond)		115	13.2Y		89.6	2				
10	)		115Y	34.5Y	13.2	44.8	1				
11	Short Pump-Henrico		115	34.5Y		40.	1				
12	Twelfth Street-Richmond)		115	13.2Y		150.	2				
13	)		115	34.5Y		168.	2				
14	West-Richmond		13.2	4.16Y		15.	3				
15	Westham-Henrico Co.		34.5	13.2Y		2.5	1				
16											
17	Pole Stations										
18	Goochland Co.)	(10)	19.9	7.6		5.999	18				
19	)	(2)	7.6	19.9		.334	2				
20	)	(1)	34.5	13.2		1.	3				
21	)	(1)	19.9	2.4		.167	1				
22	Hanover Co.)	(10)	19.9	7.6		2.5	10				
23	)	(2)	34.5	13.2		.666	2				
24											
25											

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1	Richmond District Cont.										
2	Henrico Co.)	(10)	34.5	13.2		10.664	35				
3	)	(4)	34.5	4.2		3.298	12				
4	)	(25)	19.9	7.6		9.331	31				
5	)	(2)	19.9	2.4		.833	3				
6	Louisa Co.	(1)	19.9	7.6		.167	1				
7	City of Richmond)	(4)	34.5	13.2		4.332	9				
8	)	(4)	34.5	4.2		3.667	11				
9	)	(7)	19.9	7.6		2.166	7				
10	)	(2)	19.9	2.4		.666	2				
11	)	(1)	13.2	2.4		1.5	1				
12	)	(1)	13.2	4.2		1.	1				
13											
14											
15											
16											
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1	CENTRAL DIVISION										
2	East Richmond District-Virginia										
3	Cedar-Richmond		13.2	4.16Y		3.45	3	1-1667			
4	Highland Park-Henrico Co.		13.2	4.16Y		3.75	1				
5	Mechanicsville-Henrico Co.		34.5	13.2Y		40.	2				
6	Northeast-Henrico Co.)		230	34.5Y		184.	2				
7	)		115	13.2Y		40.	2				
8	Providence Forge-New Kent Co.		115	34.5Y		22.4	1				
9	Sandston-Henrico Co.		13.2	4.16		3.	3				
10	Turner-Henrico Co.		115Y	34.5Y	13.2	67.0	2				
11	Venter-King William Co	(1)	34.5	12.5		1.5	3				
12											
13	Pole Stations										
14	Charles City Co.)	(1)	34.5	13.2		.666	2				
15	)	(5)	19.9	7.6		1.667	5				
16	Hanover Co.)	(29)	19.9	7.6		8.431	29				
17	)	(5)	34.5	13.2		4.832	14				
18	Henrico Co.)	(6)	34.5	13.2		3.667	15				
19	)	(13)	19.9	7.6		3.999	13				
20	King William Co.	(2)	19.9	7.6		.500	2				
21	New Kent Co.)	(1)	34.5	13.2		1.5	3				
22	)	(5)	19.9	7.6		1.666	5				
23											
24											
25											

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation # (b)	VOLTAGE - KV# Primary (c)	VOLTAGE - KV# Secondary (d)	VOLTAGE - KV# Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	East Richmond District	Cont.									
2	City of Richmond)	(2)	34.5	13.2		1.	5				
3	)	(6)	34.5	4.2		5.994	18				
4	)	(1)	19.9	7.6		.167	1				
5	)	(2)	13.2	4.2		1.449	6				
6											
7											
8											
9											
10											
11											
12											
13											
14											
15											
16											
17											
18											
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20											
21											
22											
23											
24											
25											

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation Ø (b)	VOLTAGE - KV # Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	EASTERN DIVISION										
2	Norfolk District-Virginia										
3	Ashton-Norfolk		13	4.16Y		3	3				
4	Bayside-Va. Beach		115Y	34.5Y	13.2	56	1				
5			115	13.2Y		22.4	1				
6			34.5	13.2Y		20	1				
7	Bayview-Norfolk		34.5	4.16Y		4.687	1				
8	Bollingbrook-Norfolk		34.5	4.16Y		4.687	1				
9	Cottage Park-Norfolk		34.5	13.2Y		25.74	2				
10	Cove Street-Norfolk		34.5	13X11Y		93.6	3				
11	Cromwell Drive-Norfolk		34.5	4.16Y		4.687	1				
12	Davis Corner-Va. Beach		115/34.5	Auto	13.2	94.8	2				
13			115	13.2Y		42.4	2				
14	Diamond Springs-Va. Beach		34.5	13.2Y		12.5	1	2-4.444			
15	East Ocean View-Norfolk		34.5	13.2Y		23.7	2				
16	Edgewater-Norfolk		34.5	4.16Y		6.25	1				
17	Fairmount Park-Norfolk		34.5	4.16Y		4.687	1				
18	Fox Hall-Norfolk		34.5	4.16Y		4.687	1				
19	Gowrie Park-Norfolk		34.5	4.16Y		4.687	1				
20	Green Hill- Norfolk		34.5	4.16Y		4.687	1				
21	Green Run-Va. Beach		230	34Y	13.2	280	2				
22	Industrial Park-Norfolk		115/34.5	Auto	13.2	75	1				
23			13.0	4.16Y				5-8.16			
24			11	4.16Y				5-8.14			
25											

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1982

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

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Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation ß (b)	VOLTAGE -KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	Norfolk District-Virginia (Cont'd)										
2	Industrial Park-Norfolk		115	13.2Y		42.4	2				
3	Killam-Norfolk		34.5	4.16Y		5.6	1				
4	Lafayette-Norfolk		34.5	4.16Y		6.25	1				
5	Lakeland-Norfolk		34.5	4.16Y		4.687	1				
6	Lenox-Norfolk		34.5	4.16Y		4.687	1				
7	McLaughlin-Norfolk		34.5	4.16Y		18.75	2				
8			115/34.5	Auto	13.2	50	1				
9	Norview-Norfolk		34.5	4.16Y		4.687	1				
10											
11	Oakwood-Norfolk		115/34.5	Auto	13.2	50	1				
12			115	34.5Y	13.2	112	2				
13			115	13.2Y		42.4	2				
14	Ocean View-Norfolk		34.5	4.16Y		9.374	2				
15	Reeves Avenue-Norfolk		115/34.5	Auto	13.2	252	3				
16			34.5	4.16		1.5	1				
17	Riverview-Norfolk		34.5	4.16Y		5	1				
18	Salter-Norfolk		34.5	4.16Y		4.687	1				
19	Sewells Point-Norfolk		230Y	34.5Y	13.2	336	2				
20	Taussig-Norfolk		115	13.2Y		22.4	1				
21	Thole Street-Norfolk		115Y	34.5Y	13.2	56	1				
22											
23											
24											
25											

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation ƒ (b)	VOLTAGE - KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	Norfolk District - Virginia (CONT'D)										
2	Thalia-Va. Beach		230Y	34.5Y	13.2	224	2				
3			34.5	13.2		44.8	2				
4	Titustown-Norfolk		34.5	4.16Y		4.687	1				
5	Westminster-Norfolk		34.5	13.2Y		11.74	1				
6	Willoughby-Norfolk		34.5	13.2Y		12.5	1				
7			13.2	4.16Y		1.875	1				
8	Military Highway		34.5	4.16Y		2.8	1				
9	Reeves Avenue-Norfolk		115Y	13.2				3-40.0			
10	Diamond Springs-Va. Beach		13.2Y	4.16		3.0	3	1-1.0			
11											
12											
13											
14											
15											
16											
17											
18											
19											
20											
21											
22											
23											
24											
25											

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

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1	EASTERN DIVISION										
2	Chesapeake District-Virginia										
3	Berkley-Chesapeake		115	13X11Y		100.0	2				
4			13.2	4.16Y		3.0	3	1-1.0			
5	Campostella-Chesapeake		11	4.16Y		3.0	3				
6	Cofield-Chesapeake		13.2/11	Auto		3.0	1				
7	Dozier-Chesapeake		115	13.2Y		42.4	2				
8			34.5/13.2	Auto		10.0	1				
9	Great Bridge-Chesapeake		115Y	34.5Y	13.2	44.8	2				
10	Hickory-Chesapeake		115Y	34.5Y	13.2	22.4	1				
11	Portlock-Chesapeake		11	4.16Y		2.25	3				
12	South Norfolk-Chesapeake		115	13.2Y		42.4	2				
13	Thompsons Corner-Va. Beach		115Y	34.5Y	13.2	112	2				
14			115	13.2		42.4	2				
15	Thrasher-Chesapeake		115Y	34.5Y	13.2	56	1				
16											
17											
18											
19											
20											
21											
22											
23											
24											
25											

Page 425

Next Page is 427

Name of Respondent	This Report Is:	Date of Report	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

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1	EASTERN DIVISION										
2	Peninsula District-Virginia										
3	Bloxoms Corner-Hampton		115	23Y		50	2				
4	Briarfield-Newport News		23	6Y		7.5	3				
5	Buckroe-Hampton		23	6Y		9.375	1				
6	Colony-Newport News		115	34.5Y		131	2	1-50MVA			
7			115	13.2Y		20	1				
8			34.5	13.2Y		20	1				
9	Copeland Park-Newport News		115	23Y		44.8	2				
10	Denbigh-Newport News		230	34.5		44.8	1				
11	East End-Newport News		23	6Y		4.686	3				
12	Grafton-York County		115	12.5Y		20	1				
13	Hampton-Hampton		23	6Y		6	3				
14	Hilton-Newport News		34.5	6Y		8.625	3				
15	Ivy-Newport News		23	6Y		4.686	3				
16	Lebanon-Newport News		115	34.5Y		22.4	1				
17			115	13.2Y		22.4	1				
18	Lee Hall-Newport News		115	12.5Y		7.5	1				
19	Magruder-Hampton		115	34.5Y		22.4	1				
20			115	12.5Y		22.4	1				
21	Merry Point-Newport News		34.5/13.2	Auto		12.5	1				
22	Newport News-Newport News		230	23Y		212	2				
23			115Y	10Y		37.5	6				
24			23	6Y		9.711	6				
25			23Y/11Y	Auto		30.	2				

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1	Peninsula District-Virginia (cont'd)										
2	Peninsula-Hampton		13	4				1-3.125			
3			115	34.5Y		44.8	2				
4			34.5/13.2	Auto		10.5	1				
5	Phoebus-Hampton		23	6Y		4.687	3				
6	Seaford-York County		115	34.5Y		44.8	2				
7	Shellbank-Hampton		115Y	23		110	6				
8			115	13.2Y		20	1				
9	Stuart Gardens-Newport News		23	6Y		4.686	3				
10	Virginia-Newport News		23	4.16Y		6	2				
11			6/4.16	Auto		6	2				
12	Warwick-Newport News		115	12.5Y		40	2				
13	Winchester-Hampton		115	34.5Y		76	2				
14			115	13.2		40	2				
15	Wythe-Hampton		23	6Y		4.686	3				
16	Pad #ML-93,N0027-Newport News		19.9/7.2	Auto		.167	1				
17	Pole Station-York County (8)		34.5/13.2	Auto		5.5	20				
18	Winchester-Hampton		34	13.2				1-26.6			
19	Normal School		23	13.2Y		2.0	3				
20											
21											
22											
23											
24											
25											

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1	EASTERN DIVISION										
2	Portsmouth District-Virginia										
3	Airline-Portsmouth		34.5	4.16Y		10.5	1				
4	Alexanders Corner-Portsmouth		34.5	13.2Y		22.4	1				
5			115	13.2Y		20	1				
6	Bowers Hill-Chesapeake		115Y	34.5Y	13.2	56	1				
7	Churchland-Chesapeake		115/34.5	Auto	11	30	3				
8			115Y	34.5Y	11	31.25	3				
9			115	13.2Y		22.4	1				
10			230	34.4Y	13.2	56	1				
11	Cradock-Chesapeake		115Y	34.5Y	13.2	80	2	1-8.333			
12			115Y	13.2Y		18.75	3				
13			11	4.16Y		5	1				
14	Deep Creek-Chesapeake		115	13.2Y		40.	2				
15	Fredericksburg College		34.5	13.2Y		2.499	3				
16	Gilmerton-Chesapeake		115	13.2Y		22.4	1				
17	Hodges Ferry-Chesapeake		115	13.2Y		42.4	2				
18	Laurel-Portsmouth		34.5	4.16Y		9.374	2				
19	Pine Street-Portsmouth		34.5	11Y		15	2				
20	Port Norfolk-Portsmouth		34.5	4.16Y		9.374	2				
21	Prentis Park-Portsmouth		34.5	4.16Y		4.687	1				
22											
23	Naval Hospital		34.5	13.2Y		8.4	1				
24											
25											

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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation ϕ (b)	VOLTAGE - KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	Portsmouth District-Virginia (Cont'd)										
2	Queen Street-Portsmouth		34.5	4.16Y		4.687	1				
3	Shea-Portsmouth		115Y	34.4Y	13.2	56	1				
4			34.5Y	13.2		20	1				
5			34.5	4.16Y		5	1				
6	Simonsdale-Portsmouth		11	4.16Y		3.75	3				
7	Victory-Portsmouth		11	4.16Y		3.916	1				
8	Westhaven-Portsmouth		34.5	4.16Y		7.187	2				
9											
10											
11											
12											
13											
14											
15											
16											
17											
18											
19											
20											
21											
22											
23											
24											
25											

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation (b)	VOLTAGE - KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	EASTERN DIVISION										
2	Suffolk District-Virginia										
3	Benns Church-Isle of Wight County		34.5/13.2	Auto		12.5	1				
4	Drivers-Suffolk		34.5	12.5Y		5.76	3	1-1.15			
5	Franklin-Southampton County		115	13.2Y		22.4	1				
6			115Y	13.2		12.5	3	1-4.444			
7	Holland-Suffolk		115Y	12.5Y		3.0	3	1-1.0			
8			12.5	2.4		1.5	3				
9	Ivor-Southampton County		115Y	12.5		5.0	1				
10	Kings Fork-Suffolk		115	13.2Y		14.0	1				
11	Lee Street-Suffolk		12.5	4.16Y		10.0	2				
12	Myrtle-Suffolk		115Y	2.4		2.75	7	1-0.333			
13			12.5	2.4		2.5	3				
14	Oakridge-Chesapeake		115	13.2Y		22.4	1				
15	Packers-Town of Smithfield		23	2.4		1.8	3				
16	Pagan-Isle of Wight County		34.5	13.2Y		4.687	1				
17	Smithfield-Isle of Wight County		230	34.5Y		112	2				
18	Spring Grove-Surry County		34.5	13.2Y		1.5	3	1-0.5			
19	Suffolk-Suffolk		115Y	12.5		40	3	1-13.333			
20			12.5	2.4		5.0	1				
21			115Y	34.5		22.4	1				
22											
23											
24											
25											

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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1	Suffolk District-Virginia (Cont'd)										
2	Union Camp-Southampton Co.		115Y	13.2		72.5	3				
3	Pole Stations-Isle of Wight Co. (5)		19.9	7.6		1.8	9				
4	Pole Stations-Surry Co. (4)		19.9/34.5	7.6/13.2		1.832	6				
5	Pad Station-Isle of Wight (1)		19.9/34.5	7.2/12.5		5	2				
6	Pad Station-Suffolk (4)		7.2/12.5	19.9/34.5		12.5	5				
7	Pole Station-Southampton Co. (1)		2.2Y	2.3Y		.6	3				
8	Pole Station-Suffolk (1)		2.4Y	19.9Y		.5	3				
9											
10											
11											
12											
13											
14											
15											
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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1	EASTERN DIVISION										
2	Virginia Beach District-Virginia										
3	Arctic-Va. Beach		34.5	4.16Y		5	1				
4			34.5	13.2		14	1				
5	Atlantic-Va. Beach		34.5	13.2Y		40	2				
6	Groveland-Va. Beach		34.5	13.2Y		9.375	1				
7	Long Creek-Va. Beach		115Y	34.5Y	13.2	22.4	1				
8	Lynnhaven-Va. Beach		115	13.2Y		42.4	2				
9	North Virginia Beach-Va. Beach		34.5	13.2Y		22.4	2				
10	Pendleton-Va. Beach		115/34.5	Auto	13.2	96	2				
11	Princess Anne-Va. Beac		115Y	34.5Y	13.2	56	1				
12	Rosemont-Va. Beach		34.5	13.2Y		6.25	1				
13	Sandbridge-Va. Beach		34.5	13.2Y		20	1				
14	Va. Beach- Va. Beach		115/34.5	Auto	13.2	168	2				
15			115	13.2Y		42.4	2				
16	Long Creek-Va. Beach		115Y	34.5Y		22.4	1				
17											
18											
19											
20											
21											
22											
23											
24											
25											

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

SUBSTATIONS *b, DISTRIBUTION SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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1	EASTERN DIVISION										
2	Williamsburg District-Virginia										
3	Carroll-Williamsburg		34.5/13.2	Auto		5	1				
4	Kingsmill-James City Co.		115	34.5Y		22.4	1				
5			230	36.5Y		44.8	1				
6	Lanexa-New Kent Co.		115	13.2Y		14	1				
7	Toano-James City County		115	36.5Y		22.4	1				
8	Waller-York County		115	13.2Y		20	1				
9			230	36.5Y		129	2				
10	Williamsburg-Williamsburg		13.2	2.4		3	3				
11	Pole Station-Charles City Co.		19.9/7.6	Auto		.167	1				
12	Pole Stations-James City Co. (2)		24.5/13.2	Auto		2.333	7				
13											
14	Eastern State		34.5	4.16Y		4.687	1				
15											
16											
17											
18											
19											
20											
21											
22											
23											
24											
25											

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1	NORTHERN DIVISION										
2	ALEX-ARLINGTON DISTRICT-VIRGINIA										
3	Alexandria Plant - Alexandria		34.5Y	4.16Y		10.	6				
4											
5	Arlington-Arlington Co.)		230	34.5Y		150.	1				
6	)		34.5	12.5Y		22.4	1				
7	)		230	34.5		168.	2				
8											
9	Bailey's Crossroads-Fairfax Co.		34.5	12.5Y		40.	2				
10	Barcroft-Arlington Co.		34.5	4.16Y		5.75	3				
11	Beverly Hills-Alexandria)		34.5	4.16Y		4.991	3				
12	)		34.5Y	4.16Y		4.687	1				
13	Cherrydale-Arlington Co.		34.5	12.5Y		14.	1				
14	Chesterbrook-Fairfax Co.		34.5	12.5Y		14.	1				
15	CIA-Fairfax Co.)		230	34.5Y		168.	2				
16											
17	Ballston-Arlington Co.		34.5	4.16Y		8.15	1				
18	Crystal-Arlington Co.		230	34.5Y		300.	2				
19	Falls Church		230	34.5Y		168.	2				
20	Falls Church-Arlington Co.		34.5	12.Y		42.4	2				
21	Payette Street-Alexandria		34.5Y	4.16Y		12.9	6				
22											
23											
24											
25											

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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1	Alex-Arlington District-Virginia (Cont.)										
2	Fort Myer-Arlington Co.)		34.5	12.5Y		9.375	1				
3	)		34.5	4.16Y		5.	1				
4	Glen Carlyn-Arlington Co.)		230	34.5Y		159.	2				
5	)		34.5	12.5Y		12.5	1				
6											
7	Glebe		230	34.5		84.	1				
8	Harrison Street-Arlington Co.		34.5	4.16Y		6.5	1				
9											
10											
11	Hillwood-Fairfax Co.		34.5	12.5Y		26.5	2				
12											
13	Hume-Alexandria		34.5Y	4.16Y		9.312	6				
14	Idylwood-Fairfax Co.)		230	34.5Y		336.	2				
15	)		34.5	12.5Y		20.	1				
16	Igloo-Fairfax Co.		34.5	12.5Y		14.	1				
17	Jefferson Street-Alexandria		230	34.5Y		336.	2				
18	Lemon-Fairfax Co.		34.5	12.5Y		12.5	1				
19	Livingston Heights-Arlington Co.		34.5	12.5Y		22.4	1				
20	McLean-Fairfax Co.		34.5	12.5Y		42.4	2				
21	Pickett Street-Alexandria		34.5	12.5Y		12.5	1				
22	Pimmit-Fairfax Co.		34.5	12.5Y		9.375	1				
23	Marymont		34.5	2.		1.500	1				
24											
25											

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

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1	Alex.-Arlington District-Virginia (Cont.)										
2	Potomac-Alexandria		23.0Y	4.16Y		10.438	7				
3	Reed-Arlington Co.		34.5	12.5Y		40.	2				
4	Seminary-Alexandria		34.5	12.5Y		11.2	1				
5	Shirley Duke-Alexandria		34.5	12.5Y		44.8	2				
6											
7	Telegraph Road-Alexandria		34.5	12.5Y		14.	1				
8											
9	Westcott-Fairfax Co.		34.5	12.5Y		40.	2				
10	Willston-Fairfax Co.		34.5	12.5Y		14.	1				
11	Woodward-Alexandria		34.5Y	4.16Y		4.311	3				
12											
13											
14											
15											
16											
17											
18											
19											
20											
21											
22											
23											
24											
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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1	NORTHERN DIVISION										
2	Fairfax District-Virginia										
3	Braddock-Fairfax Co.)		230	34.5Y		196.	2				
4			34.5	12.5Y		12.5	1				
5											
6	)		34.5Y	12.5Y		22.4	1				
7	Burke-Fairfax Co.		115	34.5Y		150.	2				
8	Chantilly-Fairfax Co.		34.5	12.5		4.687	1				
9	Clark-Fairfax Co.		230	34.5Y		224.	2				
10	Cub Run-Fairfax Co.		115	13.8		12.5	1				
11	Fairfax-Fairfax Co.		34.5	12.5Y		42.4	2				
12	Ilda-Fairfax Co.		34.5	12.5Y		20.575	2				
13	Jermantown-Fairfax Co.		34.5	12.5Y		22.4	1				
14											
15											
16											
17	Merrifield-Fairfax Co.		34.5	12.5Y		40.	2				
18	Sully-Fairfax Co.		115	34.5Y		90.	2				
19	Vienna-Town of Vienna		34.5	12.5Y		22.4	1				
20	Pender-Fairfax Co.		230	34.5		129.	2				
21											
22											
23											
24											
25											

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation ø (b)	VOLTAGE - KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	NORTHERN DIVISION										
2	Fredericksburg District-Virginia										
3	Arnold's Corner-King George Co.		115	34.5Y		22.4	1				
4	Caroline-City of Fredericksburg		13.2	4.16Y		6.252	3				
5	Colonial Beach-Westmoreland Co.		34.5	12.5Y		6.250	1				
6	Fredericksburg-City of Fredericksburg)		115	34.5Y		75.	1				
7	)		115	13.2Y		42.4	2				
8	)		230	34.5Y		84.	1				
9	)		13.2	4.16Y		3.	3				
10	Heflin-Stafford Co.		34.5	12.5Y		12.	1				
11	Hustle-Essex Co.		34.5	12.5Y		2.1	1				
12	King George-King George Co.		34.5	12.5Y		7.	1				
13	Lee-Stafford Co.		34.5	12.5Y		3.75	3				
14	Oak Grove-Westmoreland Co.		115	34.5Y		44.8	2				
15	Office Hall-King George Co.		34.5	12.5Y		2.8	1				
16	Owens-King George Co.		34.5	12.5Y		3.5	1				
17	St. Johns-Caroline Co.		115	13.2Y		12.5	1				
18	Stafford-Stafford Co.)		115	34.5Y		22.4	1				
19	)		230	34.5		45.	1				
20	Slabtown-Spotsylvania Co.		115	12.5Y		5.001	3				
21											
22											
23											
24											
25											

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation Ø (b)	VOLTAGE - KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	NORTHERN DIVISION										
2	Herndon District-Virginia										
3	Dulles-Fairfax Co.)		115	34.5Y		40.	1				
4	)		115	12.5Y		40.	2				
5	Herndon-Town of Herndon		34.5	12.5Y		12.5	1				
6	Odricks Corner-Fairfax Co.		34.5	12.5Y		9.375	1				
7	Reston-Fairfax Co.		230	34.5Y		196.	2				
8	Sterling Park-Loudoun Co.		34.5	12.5Y		44.8	2				
9	Tysons-Fairfax Co.		230	34.5Y		168.	2				
10	Sterling Park-Loudoun Co.		230	34.5Y		168.	2				
11											
12											
13											
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FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation ß (b)	VOLTAGE - KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	NORTHERN DIVISION										
2	Leesburg District-Virginia										
3	Leesburg-Loudoun Co.		34.5	12.5Y		32.5	2				
4	Lovettsville-Loudoun Co.		34.5	12.5Y		3.45	3				
5	Middleburg-Loudoun Co.)		115.	34.5Y		44.8	2				
6	)		34.5	12.5Y		4.7	2				
7	Pleasant View-Loudoun Co.)		230.	34.5Y		56.	1				
8	)		230Y	34.5		56.	1				
9	Purcellville-Loudoun Co.		34.5	12.5Y		13.75	2				
10											
11											
12											
13											
14											
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Name of Respondent	This Report Is:	Date of Report	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

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1	NORTHERN DIVISION										
2	Warrenton District-Virginia										
3	Elm-Town of Warrenton)		34.5	12.5Y		21.875	2				
4	)		34.5	4.16Y		1.5	1				
5	Gainesville-Prince William Co.		115	34.5Y		62.4	2				
6	Goldmine-Fauquier Co.		34.5	12.5Y		10.5	1				
7	Middleton-Fauquier Co.		34.5	12.5Y		2.8	1				
8	New Baltimore-Fauquier Co.		34.5	12.5Y		8.	1				
9	Old Tavern-Fauquier Co.		34.5	12.5Y		3.45	3				
10	Remington-Fauquier Co.)		115	34.5Y		22.4	1				
11	)		34.5	12.5Y		3.219	3	1-1073			
12											
13											
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FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b, DISTRIBUTION SUBSTATIONS

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1	NORTHERN DIVISION										
2	Woodbridge District-Virginia										
3	Dumfries-Prince William Co.)		115	34.5Y		42.4	2				
4	)		34.5	13.2Y		4.687	1				
5											
6	Lorton-Fairfax Co.		34.5	12.5Y		12.5	1				
7	Occoquan-Fairfax Co.)		115	34.5Y		40.	1				
8	)		230	34.5Y		33.6	1				
9	Quantico-Prince William Co.		115	13.2Y		42.4	2				
10	Woodbridge-Prince William Co.		230	34.5Y		168.	2				
11											
12											
13											
14	Lakeridge-Prince William Co.		230	34.5Y		44.8	1				
15	Cannon Branch-Prince William Co.)		115	34.5Y		22.4	1				
16	)		34.5	12.5Y		3.125	1				
17	Manassas-Town of Manassas		115	12.5Y		22.4	1				
18	Woods-Town of Manassas		115	12.5Y		22.4	1				
19	Moore DP-Co-op		34.5	13.2Y		12.5	1				
20											
21											
22											
23											
24											
25											

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

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1	NORTHERN DIVISION										
2	Springfield District-Virginia										
3	Annandale-Fairfax Co.		34.5	12.5Y		40.	2				
4	Belle Haven-Fairfax Co.		34.5	12.5Y		14.	1				
5	Engleside-Fairfax Co.		34.5	12.5Y		40.	2				
6	Fort Hunt-Fairfax Co.		34.5	12.5Y		40.	2				
7	Gallows Road-Fairfax Co.		230	34.5Y		168.	2				
8	Gum Springs-Fairfax Co.		230	34.5Y		168.	2				
9	Hayfield-Fairfax Co.		230	34.5Y		224.	2				
10	Hollin Hall-Fairfax Co.		34.5	12.5Y		22.4	1				
11	Keene Mill-Fairfax Co.		230	34.5Y		196	4				
12	Springfield-Fairfax Co.		34.5	12.5Y		42.4	2				
13	Van Dorn-Fairfax Co.		230	34.5Y		196.	2				
14	Virginia Hills-Fairfax Co.		34.5	12.5Y		20.	1				
15											
16											
17											
18											
19											
20											
21											
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SUBSTATIONS

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1	SOUTHERN DIVISION										
2	Ahoskie District-North Carolina										
3	Academy-Hertford Co.		34.5	4.16Y		4.687	1				
4	Aulander-Bertie Co.		34.5	4.16Y		1.0	3				
5	Bertie-Hertford Co.		34.5	13.2Y		3.125	1				
6	Conway-Northampton Co.		34.5	12.5Y		2.0	1				
7	Earleys-Hertford Co.		115	34.5Y		42.4	2				
8	Harrellsville-Hertford Co.		34.5	13.2Y		3.125	1				
9	Milwaukee-Northampton Co.		34.5	12.5Y		1.5	3				
10	Murfreesboro-Hertford Co.		34.5	4.16Y		3.75	1				
11	Murphy-Hertford Co.		115	34.5Y		22.4	1				
12	Parker-Northampton Co.		34.5	4.16Y		1.0	3	1- .333			
13	Rich Square-Northampton Co.		34.5	2.4		1.5	3				
14	Roxobel-Bertie Co.		34.5	4.16Y		.750	6				
15	Scotland Neck-Halifax Co.		115Y	12.5Y	2.4	13.332	3	1-4.444			
16	Trap-Bertie Co.		34.5	13.2Y		7.5	1				
17	Tunis-Hertford Co.		115	34.5Y		40.0	1	1-32.0			
18	Wading Creek-Bertie Co.		34.5	13.2Y		1.0	2	1- .500			
19	Winton-Hertford Co.		34.5	13.2Y		2.0	3				
20	Woodland-Northampton Co.		115	34.5		12.5	1				
21	Woodville-Bertie Co.		34.5	4.16Y		.900	6				
22	Sam's Head-Halifax Co.		115	12.5Y		6.24	3	1-1.667			
23											
24											
25											

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FERC FORM NO. 1 (REVISED 12-81)

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1	SOUTHERN DIVISION										
2	Ahoskie District-North Carolina (Cont'd)										
3											
4	Kelford-Bertie Co.		115	34.5Y		22.4	1				
5											
6	Pole Stations-Hertford Co.)	(1)	19.9/7.62	Auto		.333	1				
7		(2)	34.5/12.5	Auto		2.000	6				
8	Pole Stations-Hertford Co.)	(6)	19.9/7.6	Auto		1.666	6				
9		(1)	34.5/13.2	Auto		.666	2				
10		(2)	19.9	2.4		.334	4				
11	Pole Stations-Hertford Co.	(2)	34.5	13.2		2.000	6				
12	Pole Stations-Hertford Co.	(1)	19.9	7.62		.333	1				
13	Pole Stations-Bertie Co.)	(2)	19.9/7.62	Auto		.666	2				
14		(1)	19.9	2.4		.167	1				
15	Pole Stations-Northamtpon	(2)	19.9	2.4		.500	3				
16		(1)	34.5/12.5	Auto		.666	2				
17											
18											
19											
20											
21											
22											
23											
24											
25											

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Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	*See Above Character of Substation ø (b)	VOLTAGE - KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	SOUTHERN DIVISION										
2	Albemarle District-North Carolina										
3	Albemarle-Bertie Co.		115	34.5Y		15.0	3				
4	Columbia-Tynell Co.		34.5	12.5Y		5.250	1				
5	Conaby-Wash9ngton Co.		34.5	4.16Y		3.750	3				
6	Creswell-Washington Co.		34.5	12.5Y		6.25	1				
7			115	34.5		22.400	1				
8	Edgecombe-Edgecombe Co.		34.5	12.5		14.0	1				
9											
10	Everetts-Martin Co.	115Y/	34.5Y	Auto	13.2	65.0	4	1-6.667			
11	Hamilton-Martin Co.		34.5	4.16		1.0	3				
12	Legetts X-Roads-Beaufort Co.		115	12.5		2.280	3	1- .760			
13	Lilley-Martin Co.		34.5	12.5Y		14.0	1				
14	Parmele-Pitt Co.		115	12.5Y		12.5	.1				
15	Plymouth-Washington Co.		115	34.5Y		42.4	2				
16	Pungo River-Beaufort Co.		34.5	4.16Y		7.5	1				
17	Robersonville-Martin Co.		12.5	4.16Y		10.250	2				
18	Robersonville-Martin Co.		115	12.5		12.5	1				
19	Roper-Washington C o.		34.5	12.5Y		2.500	3				
20	Tarboro-Edgecomba Co.		115Y	34.5Y	13.8	13.332	3	4.444			
21			115	34.5Y		14.0	1	4-1.667			
22	Tarboro Town-Edgecombe Co.		115	13.2Y		22.4	1				
23	Jamesville-Martin Co.		34.5	12.5Y		3.750	3				
24											
26											

Next Page is 427

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

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Line No.	Name and Location of Substation (a)	*See Above Character of Substation β (b)	VOLTAGE - KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	SOUTHERN DIVISION										
2											
3	Albemarle District-North Carolina		(Cont'd)								
4	Tar River-Edgecombe Co.		115	12.5Y		22.4	I				
5	Williamston-Martin Co.		34.5	4.16Y		3.5	1				
6	Wilson-Robersonville-Martin Co.		115	12.5Y		3.750	1				
7	Windsor-Carolina-Bertie Co.		.34.5	13.2Y		9.375	1				
8	Vaughan-Edgecombe Co.		115	13.2Y		22.4	1				
9											
10											
11	Pole Station-Martin Co.)	(1)	34.5Y	12.5		.666	2				
12		(4)	19.9/7.2	Auto		1.0	4				
13	Pole Stations-Tyrrell Co.)	(2)	19.9/7.2	Auto		1.333	4				
14		(1)	12.5Y	4.16Y		.100	2				
15	Pole Stations-Washington Co.	(1)	34.5Y/12.5Y	Auto		1.000	3				
16		(13)	19.9/7.2	Auto		3.000	13				
17		(2)	34.5	4.16		2.000	6				
18		(3)	19.9	2.4		1.666	5				
19	Five Points-Beaufort Co.		115	34.5Y		22.4	1				
20	Pad Station-Martin Co.	(1)	34.5	12.5Y	Auto	2.000	1				
21	Bethel-Carolina-Pitt Co.		115	12.5Y		20.0	1				
22											
23											
24											
25											

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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Line No.	Name and Location of Substation (a)	*See Above Character of Substation (b)	VOLTAGE - KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	SOUTHERN DIVISION										
2	Altavista District-Virginia										
3											
4	Chatham-Pittsylvania Co.		69	12.5Y		12.501	3				
5	Gretna-Pittsylvania Co.		69	12.5Y		9.375	3	3.125			
6	Otter River-Campbell Co.		115	12.5Y		22.4	1				
7	Perth-Halifax Co.		69	12.5Y		3.750	3				
8	Staunton River-Campbell Co.)		69	12.5Y		6.25	3				
9	)		69	12.5		7.5	3				
10			69	12.5		7.5	3				
11											
12											
13											
14											
15											
16											
17											
18											
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20											
21											
22											
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1	SOUTHERN DIVISION										
2	Elizabeth City District-North Carolina										
3											
4	Barco-Currituck Co.		115	13.2Y		5.0	3				
5	Edenton-Chowan C o.)		115	13.2Y		22.4	1				
6	)		12.5Y/34.5Y	Auto		10.0	1				
7	Elizabeth City-Pasquotank Co.		115Y /34.5Y	Auto	13.2	80.0	2	1-20.			
8			34.5	13.2Y		4.311	3				
9	Gatesville-Gates Co.		34.5	12.5Y		4.687	1				
10	Hertford-Perquimans Co.		34.5	4.16Y		3.750	3				
11											
12	Okisko-Poquotank Co.		34.5	12.5Y		5.0	1				
13	Shawboro-Currituck Co.		115	13.2Y		5.75	3				
14	Snow Hill-Chowan Co.		34.5	12.5Y		2.5	6	1-.333			
15	Sunbury-Gates Co.		34.5	12.5Y		3.5	1				
16	Winfall-Perquimans Co.		115	34.5Y		25.0	4	1-3.333			
17	Pole Stations-Chowan Co.)	(3)	19.9/7.2	Auto		.667	3				
18		(2)	34.5/13.2	Auto		1.333	4				
19											
20											
21											
22											
23											
24											
25											

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1	ELIZABETH CITY DISTRICT - North Carolina										
2											
3	Pole Stations-Gates Co.	(2)	34.5Y/12.5Y	Auto		1.166	5				
4	Pad Stations-Pasquotank Co.	(2)	34.5Y/13.2Y	Auto		4.5	2				
5	Pole Stations-Pasquotank Co.	(1)	19.9/7.6	Auto		.333	1				
6	Pole Stations-Perquimans Co.	(1)	34.5Y/12.5Y	Auto		.500	3				
7	Pad Mount Stations-Currituck Co.	(1)	34.5Y/13.2Y	Auto		2.0	1				
8	Pole Station-Perquimans Co.	(2)	19.9/7.6	Auto		.333	2				
9	Pole Station-Camden Co.	(1)	19.9/716	Auto		.167	1				
10	Pad Station-Camden (1)		34.5	13.2		2.0	1				
11	Pad Station-Gates Co.	(1)	34.5/12.5	Auto		2.5	1				
12											
13											
14											
15											
16											
17											
18											
19											
20											
21											
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1	SOUTHERN DIVISION										
2	Farmville District-Virginia										
3											
4	Amelia-Amelia Co.		34.5	12.5Y		2.874	3				
5	Buckingham-Cumberland	Co.	230	34.5Y		33.6	1				
6			34.5	12.5Y		2.5	1				
7	Fort Pickett-Nottoway	Co.	115	12.5Y		14.0	1				
8	Crewe-Nottoway Co.		115	12.5Y		14.0	1				
9	Dillwyn-Buckingham Co.		34.5	12.5Y		3.125	1				
10	Farmville-Cumberland Co.)		115	12.5Y		22.4	1				
11	)		115Y	12.5		20.0	1				
12	)	12.5Y/34.5Y		Auto		10.5	1				
13	Jetersville-Nottoway Co.		115	34.5Y		15.0	3	1-4.167			
14	Pamplin-Prince Edward	Co.	115	34.5Y		44.8	2				
15		)34.5		23Y		6.0	3	1-2.0			
16	South Creek-Appomattox	Co.	34.5	12.5Y		10.500	1				
17			115	13.2Y		22.400	1				
18	Pole Station-Appomattox Co. (2)		34.5	12.5		1.5	6				
19	Pole Station-Appomattox Co. (3)		19.9	7.2		.500	3				
20											
21											
22											
23											
24											
25											

FERC FORM NO. 1 (REVISED 12-81)

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1	SOUTHERN DIVISION										
2	Farmville District-Virginia (Cont'd)										
3											
4	Pole Stations-Buckingham Co. (3)		34.5Y/12.5Y	Auto		2.334	7				
5	Pole Stations-Charlotte Co. (1)		19.9/7.2	Auto		.167	1				
6	Pole Stations-Prince Edward Co. (2)		19.9/7.2	Auto		.500	2				
7	Pole Stations-Town of Pamplin (1)		34.5Y/12.5Y	Auto		1.000	3				
8											
9	Pole Stations-Buckingham Co. (2)		19.9/7.2	Auto		.334	2				
10	Pole Station-Appomattox Co. (4)		19.9/7.2	Auto		1.000	4				
11	Pad Mount Station-Appomattox Co. (1)		34.5/12.5Y	Auto		2.000	1				
12	Pad Mount Station-Prince Edward Co.		3.45/13.2Y			6.000	3	1-2.000			
13											
14											
15											
16											
17											
18											
19											
20											
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1	SOUTHERN DIVISION										
2	Outer Banks District-North Carolina										
3											
4	Jarvisburg-Currituck Co.		115	13.2Y		6.667	1				
5	Kitty Hawk-Dare Co.)		115Y/34.5Y	Auto	13.2	112,000	2				
6	)		34.5Y/13.2Y		Auto	12.500	1				
7	Manteo-Dare Co.		34.5	13.2		6.250	1				
8	Nags Head-Dare Co.		34.5	13.2		7.500	6	1.250			
9											
10	Pole Stations-Dare Co.	(7) 19.9/7.6		Auto		2.217	9				
11		(3) 19.9		2.4		1.334	5				
12		(2) 7.6		2.4		1.000	2				
13	Pad Mounted Station-Dare Co.)	(3)	34.5/13.2	Auto		6.000	3				
14		)(4)	34.5	13.2		10.00	4				
15		)(2)	34.5/13.2	Auto		10.00	2				
16		)(1)	34.5/13.2	Auto		3.750	1				
17											
18											
19											
20											
21											
22											
23											
24											
25											

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Line No.	Name and Location of Substation (a)	*See Above Character of Substation ø (b)	VOLTAGE - KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	SOUTHERN DIVISION										
2	Roanoke District-North Carolina										
3											
4	Battleboro-Nash Co.)		115Y/34.5	Auto	2.4	20,000	1				
5	)		34.5	12.5		1,000	3				
6	Benson-Edgecombe Co.		34.5Y/12.5Y	Auto		6,250	1				
7	Carolina-Halifax Co.)		115	13.2Y		80,000	2				
8	)		115Y	13.2		20,000	1				
9	Caudle-Halifax Co.		34.5Y	13.2Y		1,800	3				
10	Eaton's Ferry-Warren Co.		115	13.2Y		5,000	1				
11	Enfield-Halifax Co.		34.5	4.16Y		7.5	1				
12	Hornertown-Halifax Co.)		115	34.5Y		22,400	1				
13	)		115	13.2Y		44,800	2				
14	)		34.5Y/13.2Y	Auto		6.25	1				
15	)		13.2	4.16Y		1,500	3				
16	Jackson-Northampton Co.		13.2	2.4		1,000	3				
17	Madison-Halifax Co.		13.2	4.16Y		6,750	6	1- 1,250			
18	Margarettesville-Halifax Co.		115Y	13.2		2.5	3	1- .833			
19	Seaboard-Northampton Co.		115	13.2Y		7,500	3	1- 2,500			
20	Seaboard Town-Northampton Co.		13.2	2.4		.600	3	1- .200			
21	Weldon-Halifax Co.		13.2	2.4		1,500	3				
22	Whitakers-Nash Co.)		115Y	34.5Y	13.2	22,400	1				
23	)		34.5	13.2Y		1,500	3				
24											
25											

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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1	Roanoke District-North Carolina (Cont'd)										
2											
3											
4	Pole Stations-Edgecombe Co. (1)		19.9/7.2	Auto		.167	1				
5	Pole Stations-Halifax Co. (1)		34.5Y/13.2Y	Auto		.500	3				
6	(2)		19.9/7.6	Auto		.334	2				
7	Pole Stations-Nash Co. (1)		34.5Y/13.2Y	Auto		.666	2				
8	Pole Stations-Halifax Co.		13.2	2.4		1.000	3				
9	Pad Station - Halifax (1)		34.5/13.2	Auto		2.000	1				
10											
11											
12											
13											
14											
15											
16											
17											
18											
19											
20											
21											
22											
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1	<u>SOUTHERN DIVISION</u>										
2	<u>Roanoke District-Virginia</u>										
3											
4	Boykins-Southampton Co.		115	34.5Y		12.500	1				
5	Capron-Southampton Co.		34.5	12.5Y		3.450	3				
6	Emporia-Greensville Co.)		115	12.5Y		22.400	1				
7	)		115	4.16Y		2.850	3	1- .950			
8	Metcalf-Greensville Co.		115	12.5Y		12.000	1				
9	Tarrara-Southampton Co.		34.5	12.5Y		3.125	1				
10	Trego-Greensville Co.)		115	2.4		6.300	1				
11	)		2.4	12.5		2.800	3				
12	Pole Station-Southampton Co.	(1)	19.9/7.2 Auto			1.000	3				
13		(1)	34.5/12.5Auto			1.000	3				
14											
15											
16											
17											
18											
19											
20											
21											
22											
23											
24											
25											

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1	SOUTHERN DIVISION										
2	Southside District-Virginia										
3											
4	Chase City-Town of Chase City		115	12.5Y		14.000	1				
5	Kenbridge-Lunenburg Co.		115	12.5Y		14.000	1				
6	Lawrenceville-Brunswick Co.)		115	12.5Y		22.400	2				
7	)		12.5/34.5	Auto		10.000	1				
8	South Hill-Mecklenburg Co.		115	12.5Y		28.000	2				
9	Victoria-Lunenburg Co.		115	12.5Y		14.000	1				
10											
11	Pole Station-Mecklenburg Co.	(3)	34.5/12.5	Auto		1.500	9				
12		(1)	12.5/34.5	Auto		2.500	1				
13	Pole Station-Brunswick Co. (1)		34.5	12.5		.334	2				
14											
15											
16											
17											
18											
19											
20											
21											
22											
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1	SOUTHERN DIVISION										
2	South Boston District-Virginia										
3											
4	Central-Charlotte Co.)		115	12.5Y		22.400	1				
5	)		12.5Y/34.5	Auto		6.250	1				
6	Clarksville-Mecklenburg Co.)		115	12.5Y		22.400	1				
7	)		69Y	12.5Y	2.4	7.500	3	1-2.500			
8	Clover-Halifax Co.		115	12.5Y	2.4	6.250	3	1-2.083			
9											
10	Kinderton-Mecklenburg Co.		115	12.5Y		20.000	1				
11											
12	Omega-Co-op		115	13.2Y		5.249	1				
13	Reedy Creek-Halifax Co.		115	34.5		12.500	1				
14	South Boston-City of South Boston)		115	12.5Y		20.000	1				
15	)		115	12.5		15.000	1				
16	Welco-Halifax Co.		115	12.5		15.000	1				
17	Sinai-Halifax Co.		115	12.5		14.000	1				
18	Pole Stations-Charlotte Co.)(1)		12.5Y/34.5Y	Auto		.500	3				
19											
20											
21											
22											
23											
24											
25											

Next Page is 427

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

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1	South Boston District-Virginia (Cont'd)										
2	Pole Stations-Charlotte Co.)	(1)	34.5Y/12.5	Auto		.500	3				
3	)	(1)	19.9/7.2	Auto		.167	1				
4	Pad Stations-Mecklenburg Co.	(1)	12.5Y/34.5Y	Auto		2,000	1				
5		(3)	19.9/7.2	Auto		.500	3				
6	Pole Station-Halifax Co.)	(2)	19.9/7.2	Auto		.334	2				
7	)	(1)	19.9	12.5		.167	1				
8											
9											
10											
11											
12											
13											
14											
15											
16											
17											
18											
19											
20											
21											
22											
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24											
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1	WESTERN DIVISION										
2	Alleghany District-Virginia										
3	Buchanan-Botetourt Co.		46	12.5Y		6.75	6				
4	Clifton Forge-City of)		138	12.5Y		22.4	1				
5	)		138Y/46Y	Auto	13.2	20.	1				
6	)		13.2	4.16Y		3.	3	2-1.0			
7	)		46	2.0				1-.625			
8	Covington-City of)		138Y/46Y	Auto	13.2	134.4	3	1-22.0			
9	)		46	12.5Y		8.4	1				
10	Dry Run-Covington		46	12.5Y		10.5	1	3-3.0			
11	Eagle Rock-Botetourt Co.		46	2.4		1.2	3				
12	Iron Gate-Alleghany Co		12.5	2.4		.450	3				
13	Jackson River-Covington)		46	12.5Y		9.75	3				
14	)		46	4.16		5.75	3	1-1.667			
15	Lewis Tunnell-Alleghany Co.		46	7.2		.250	1	2-.250			
16	Liberty Limestone-Botetourt Co.		46	2.4		3.	3				
17	T1 & T2-Bath Co.)		46	12.5		16.5	2	1-14.0			
18	)		13	4.0		2.7	1				
19											
20											
21											
22											
23											
24											
25											

FERC FORM NO. 1 (REVISED 12-81)

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Line No.	Name and Location of Substation	*SEE ABOVE Character of Substation	VOLTAGE - KV# Primary	Secondary	Tertiary	Capacity of Substation (In Service) (In MVa)	Number of Transformers in Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment	Number of Units	Total Capacity
	(a)	ø (b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	WESTERN DIVISION										
2	Augusta District-Virginia										
3	Arch Avenue-Waynesboro		23	12.5Y		3.0	3				
4			23	4.16Y		3.75	3	1-1.25			
5	Dooms-Augusta Co.)		115Y	23		50.	1	1-12.5			
6	)		23.0	13.0				1-12.5			
7	Ellard-Augusta Co.		23	12.5Y		3.00	3				
8	Fishersville-Town of		115	23Y		12.5	1				
9	Kingsburg-Augusta Co.		23	12.5Y		2.	3				
10	Nebel-Augusta Co.		23	12.5Y		5.	3				
11	Pkin-Augusta Co.		23	12.5Y		2.	6	1-.333			
12	Ridge View-Augusta Co.		23	12.5Y		2.	3				
13	Staunton-City of)		115	23Y		12.5	1				
14	)		115Y	23		20.	3	1-3.333			
15	)		115Y	13.2		20.	1				
16	)		13.2	4.16Y		7.	1				
17	)		23	12.5Y		7.5	1				
18	Stuarts Draft-Augusta Co.		115	23Y		25.0	2				
19	Third Street-Staunton)		23	12.5Y		10.5	1				
20	)		23	4.16Y		4.314	3				
21	Verona-Augusta Co.)		115	23Y		12.5	1				
22	)		115Y	23		12.5	1				
23	Wayne Hills-Waynesboro		23	12.5Y		10.5	1				
24	Waynesboro-City of		115Y	23		50.	1				
25	West Staunton-Augusta Co.)		230	23Y		45.	1				

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1	Augusta District-Virginia (Con't)										
2	West Staunton-Augusta Co.)		23Y/12.5Y	Auto		2.	1				
3	)		115	23Y				1-22.40			
4	Pole Stations-Augusta Co.	(3)	23Y	4.16Y		2.8	12				
5	Pole Stations-Augusta Co.	(1)	13.2	7.2		.200	2				
6	Pole Stations-Augusta Co.	(1)	12.5Y	4.16Y		.150	3				
7	Pole Stations-Waynesboro	(1)	23Y	4.16Y		.900	6				
8	Pole Stations-Waynesboro	(1)	12.5Y	4.16Y		.150	3				
9	Pole Stations-Albemarle Co.	(1)	23Y	12.5Y		1.	6				
10	Pole Stations-Nelson Co.	(1)	13.2			.100	1				
11	Pad Mtd. Sta.-Augusta Co.	(1)	23Y	12.5Y		3.75	1				
12											
13											
14											
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation ø (b)	VOLTAGE - KV# Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	WESTERN DIVISION										
2	Charlottesville District-Virginia										
3	Barracks Road-Albemarle Co.)		230	34.5Y		45.	1				
4	)		115	34.5Y		22.4	1				
5	)		115	12.5Y		20.	1				
6	Charlottesville-City of)		115Y/34.5Y	Auto	13.2	56.	1				
7	)		115	12.5Y		20.	1				
8	)										
9	)		230	34.5Y		75.	1				
10	Crozet-Albermarle Co.)		115Y	34.5Y		22.4	1				
11	)		230	34.5Y		45.	1				
12	Eleventh Street-Charlottesville		34.5	4.16Y		5.25	1				
13	Hydraulic-Albermarle Co.		34.5	12.5Y		11.2	1				
14	Market Street-Charlottesville		34.5	4.16Y		5.25	1				
15	Sherwood-Albermarle Co.)		115	34.5Y		56.	1				
16	Whitehall-Albermarle Co.		34.5Y/23Y	Auto		9.375	1	1-7.5			
17	Pole Stations-Albermarle Co)(13)		34.5Y/12.5Y	Auto		15.5	38				
18	Pole Stations-Albermarle Co)(31)		19.9/7.2	Auto		10.666	34				
19	Pole Stations-Charlottesville(7)		34.5Y/4.16Y	Auto		4.5	21				
20	Pole Stations-Charlottesville(5)		19.9/2.4	Auto		1.533	7				
21	Pad Mtd. Sta.-Charlottesville(3)		34.5/12.5	Auto		7.	3				
22	Pad Mtd. Sta.-Albermarle Co. (1)		34.5/12.5	Auto		2.5	1				
23	Pad Mtd. Sta.-Albermarle Co. (10)		19.9/7.2	Auto		2.833	10				
24	Pad Mtd. Sta.-Charlottesville(1)		34.5/4.16Y	Auto		1.5	1				
25											

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

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1	WESTERN DIVISION										
2	Greenbrier District-West Virginia										
3	Acme-Greenbrier Co.		46	2.4		3.	3				
4	Alderson-Town of		46	12.5Y		5.5	6	1-1.667			
5	Clenden-Greenbrier Co.		46	12.5Y		10.5	1				
6	Greenbrier-Greenbrier Co.		138Y	46Y	13.2	12.5	1				
7	Hinton-Summers Co.)		138Y	46Y	13.2	35.5	3				
8	)		46Y	12.5Y		16.94	4	3-1.0			
9	Lowell-Summers Co.		46	12.5Y		3.	3	1-1.0			
10	Renick-Greenbrier Co.		46	34.5Y		5.	1	1-5.0			
11	Ronceverte-Greenbrier Co.)		138Y/46Y	Auto	13.2	76.	3				
12	)		46	12.5Y		10.5	3				
13	Ronceverte-Lewisburg-Greenbrier Co.		46	12.5Y		9.375	3	1-1.0			
14	Rowan-Monroe Co.		46	12.5Y		5.5	6				
15	Summers-Town of Hinton)		46	2.4		1.5	3	1-.4			
16	)		12.5	2.4		1.	3	1-.333			
17	White Sulphur-Greenbrier Co.		46	12.5Y		12.5	6				
18	West Lewisburg					10.5	1				
19	Pole Stations-Greenbrier Co. (3)		19.9Y/7.2Y	Auto		.833	3				
20	Pole Stations-Pocahontas Co.)(1)		34.5Y/12.5Y	Auto		1.5	3				
21	Pole Stations-Pocahontas Co.)(4)		19.9Y/7.2Y	Auto		1.0	4				
22											
23											
24											
25											

Name of Respondent	This Report Is:	Date of Report	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

SUBSTATIONS *b. DISTRIBUTION SUBSTATIONS

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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

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Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation ø (b)	VOLTAGE - KV # Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	WESTERN DIVISION										
2	Orange District-Virginia										
3	Cuckoo-Louisa Co.		34.5	12.5Y		3.125	1				
4	Culpeper-Town of)		115	34.5Y		40.	1	1-22.4			
5	)		115	12.5Y		22.4	1				
6	Key-Louisa Co.		34.5	12.5Y		2.3	1				
7	Locust Grove-Orange Co.		115	34.5Y		40.	1				
8	Orange-Orange Co.)		115	12.5Y		20.0	1	3-4444			
9	)		12.5Y	2.4		2.5	3				
10	Culpeper No. 1-NPEC		34.5	12.5Y		12.5	1				
11	Louisa-Louisa Co.		115	34.5Y		12.5	1				
12	Somerset-Orange Co.)		115	34.5Y		44.8	2				
13	)		34.5Y	12.5Y	2.4	3.75	3	1-1.25			
14	Unionville-Orange Co.		115	12.5Y		4.2	1				
15	Wilderness-Orange Co.		34.5	12.5Y		9.375	1				
16	Pole Stations-Culpeper Co.	(4)	34.5Y/12.5Y	Auto		2.833	9				
17	Pole Stations-Louisa Co.)	(5)	34.5Y/12.5Y	Auto		2.666	13				
18	)	(7)	19.9/7.2	Auto		1.667	7				
19	Pole Stations-Orange Co.)	(1)	34.5Y/12.5Y	Auto		.500	3				
20	)	(1)	7.2	2.4		.100	1				
21	Rixley-Culpeper Co.		35.5	12.5Y		6.25	1				
22	Bremo-Fluvanna Co.)		115Y	34.5		22.4	1				
23	)		34.5Y/12.5Y	Auto		6.25	1				
24	Cartersville-Cumberland Co.		115	34.5Y		5.	3				
25	Pole Stations-Fluvanna Co.	(6)	19.2/7.2	Auto		2.5	11				

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 82

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1	Orange District-Virginia Con't										
2	Pole Stations-Cumberland Co.	(6)	19.9/7.2	Auto		1.668	6				
3	Pad Mtd. Sta.-Culpeper Co.	(2)	34.5/12.5	Auto		5.	2				
4	Pad Mtd. Sta.-Fluvanna Co.	(1)	34.5/12.5	Auto		2.5	1				
5	Pole Stations-Orange Co.	(2)	19.9/712	Auto		.666	2				
6	Pole Stations-Gordonsville	(1)	34.5/12.5Y			1.	3				
7											
8											
9											
10											
11											
12											
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15											
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUBSTATIONS

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1	WESTERN DIVISION										
2	Rockbridge District-Virginia										
3	Balcony Falls-Rockbridge Co.										
4	Bells Valley-Rockbridge Co.		115Y/46Y	Auto	2.4	30.0	3				
5	Buena Vista-City of		23	12.5Y		[illegible]	2				
6	Bustleburg-Rockbridge Co.		115Y	12.5Y		3.	3	1-1.0			
7	Craigsville-Augusta Co.)		115Y	23		6.	3	1-2.0			
8	)		23	12.5Y		1.5	3				
9	Craigsville Town-Augusta Co.)		23	2.4		1.	3				
10	Cushaw-Amherst Co.		13.2	2.4		5.	1				
11	Diamond Street-Town of Lexington		12.5	4.16Y		2.8	1				
12	Glasgow-Rockbridge Co.		46	12.5Y		10.5	3				
13	Goshen-Rockbridge Co.)		115Y/46Y	Auto	4.16	10.	3	1-3.333			
14	)		115	23Y		12.5	1				
15	)		23	4.16Y		1.8	6				
16	Rockbridge-Rockbridge Co.)		115	12.5Y		42.4	2				
17	)		34.0	13.2Y		5.6	1				
18											
19											
20											
21											
22											
23											
24											
25											

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

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1	WESTERN DIVISION										
2	Valley District-Virginia										
3	Bridgewater-Rockingham Co.		34.5Y	12.5Y		5.751	3				
4	Columbia Furnace-Shenandoah Co.		34.5Y/12.5Y	Auto		5.6	1				
5	Dayton-Rockingham Co.		115	34.5Y		44.8	2				
6	Edinburg-Shenandoah Co.		115	34.5Y		40.	2				
7	Elk Run-Town of		34.5	4.16Y		4.687	1				
8	Elkton-Rockingham Co.)		115	34.5Y		44.8	2				
9	)		34.5	12.5Y		3.125	1				
10	Endless Caverns-Rockingham Co.		115	34.5Y		20.	1				
11	Grottoes-Rockingham Co.)		115Y	23		9.375	3	1-3.333			
12	)		23	12.5Y		5.751	3				
13	)		115Y	12.5Y		6.250	3	1-2.083			
14	Harrisonburg-Rockingham Co.)		115/69	Auto	13.8	74.4	2	1-50.0			
15	)		115	34.5Y		22.4	1				
16	)		115Y	23		40.	3	1-13.333			
17	)		230/69	Auto	13.2	112.	3				
18	Massanutten-Sehnandoah Co.		34.5	12.5Y		9.375	1				
19	New Market-Shenandoah Co.		34.5	12.5Y		3.125	1				
20	Rockingham-Rockingham Co.		34.5	12.5Y		12.5	1				
21	Timberville-Rockingham Co.		115Y	12.5Y		12.5	1				
22	Weyers Cave-Rockingham Co.		115Y	34.5		10.0	1				
23	Woodstock-Shenandoah Co		34.5	12.5Y		5.625	2				
24											
25											

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1	Valley District-Virginia (Cont'd)										
2	Pole Stations-Rockingham Co.)	(2)	34.5Y/12.5Y	Auto		2.	6				
3	)	(19)	19.9/7.2	Auto		7.833	26				
4	)	(5)	7.2	2.4		.488	5				
5	)	(1)	19.9	2.4		.333	2				
6	Pole Stations-Shenandoah Co.)	(4)	34.5Y/12.5Y	Auto		3.30	12				
7	)	(13)	19.9/7.2	Auto		3.5	14				
8	)	(3)	19.9	2.4		.433	3				
9	)	(2)	7.2	2.4		.175	2				
10	Pole Stations-Augusta Co.)	(2)	19.9	7.2		.500	2				
11	)	(1)	19.9	2.4		.167	1				
12	)	(1)	7.2	2.4		.100	1				
13	Pole Sta.-Rockingham Co	(1)	19.9	7.2		.167	1				
14	Pole Sta.-Shenandoah Co	(3)	19.9	7.2		.666	3				
15	Pad Mtd. Sta.-Shenandoah Co.	(1)	19.9	7.2		.100	1				
16	TOTAL DISTRIBUTION CAPACITY					21,197.281					
17	ø All Substations are unattended except as noted.										
18	*Leased by the respondent from the Norfolk Southern Railway Company. Lease is dated March 1, 1930										
19	and extends for 99 years. The annual rental is $130,000. Non-associated Company.										
20	# Nominal circuit voltage shown.										
21											
22											
23											
24											
25											

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation	*SEE ABOVE Character of Substation	VOLTAGE - KV(E)			Capacity of Substation (In Service) (In MVa)	Number of Transformers in Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT		
		ø	Primary	Secondary	Tertiary				Type of Equipment	Number of Units	Total Capacity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	VIRGINIA										
2	Altavista-Campbell Co.)		138Y/115Y	Auto	13.2	100.	1				
3	)		138Y/115Y	Auto	13.2	53.331	3	1-17.777			
4	Basin-City of Richmond		230Y/115Y	Auto	13.2	448.	2				
5	Bearskin-Pittsylvania		138Y/69Y	Auto	13.2	44.8	1				
6	Bremo-Fluvanna Co.)	Attended	138Y/115Y	Auto	13.8	80.	3	1-26.6			
7	)		138Y/115Y	Auto	13.8	112.	1				
8	)		138Y/115Y	Auto				1-60.			
9	)		115Y	17.1		210.	2				
10	)		115Y	13.2		80.	3				
11	)		115Y	13.2				7-43.75			
12	Brunswick-Brunswick Co.		115Y/69Y	Auto	13.8	20.	3	1-5.0			
13	Bull Run-Fairfax Co.		230Y/69Y	Auto		111.	3				
14	Bull Run-Fairfax Co.		230Y/115Y	Auto	13.2	168.	3				
15	Carson-Dinwiddie Co.		500Y/230Y	Auto	36.5	840.	3	1-280.			
16	Chase City-Town of Chase City		115Y/69Y	Auto	13.8	25.	3				
17	Chesterfield-Chesterfield Co.)Atd.		230Y/115Y	Auto	13.2	224.	1				
18	)		230Y	22.9		806.4	2				
19	)		230Y	20.9		448.	1	1-400.			
20	)		115Y	20.9		210.	1				
21	)		115Y	13.8		135.	2				
22	)		115Y	13.2		140.	6	1-26.667			
23	Churchland-City of Chesapeake		230Y/115Y	Auto	13.2	224.	1				
24	Clark-Fairfax Co.		230Y/115Y	Auto	13.2	224.892	3	1-74.964			
25	Dooms-Augusta Co.		500Y/115Y	Auto		224.	1				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

SUBSTATIONS *b. Transmission

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation VIRGINIA CON'T (a)	*SEE ABOVE Character of Substation ø (b)	VOLTAGE - KV(E) Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	Elmont-Hanover Co.		500Y/230Y	Auto		1680.	6	1-280.			
2	Farmville-Cumberland Co.		500Y/230Y	Auto	13.2	336.	2				
3	Dooms-Augusta Co.		500Y/230Y	Auto	34.5	840.	3				
4	Dooms-Augusta Co.		230Y/115Y	Auto	13.2	168.	2	1-100.			
5	Fredericksburg-City of Fred'burg		230Y/115Y	Auto	36.5	168.	1				
6	Gainsville-Prince William Co.		115Y/69Y	Auto		112.	2				
7	Greenwich-City of Va. Beach		230Y/115Y	Auto	13.2	448.	2				
8	Halifax-Halifax Co.)		230Y/115Y	Auto	13.2	224.	1				
9	Harmony Village (Middlesex Co.)		230Y/115Y	Auto	13.2	168.	3	1-56.			
10	Harrisonburg-Elect. Co-op Hec.)		230Y/115Y	Auto	13.2	224.	1				
11	)		230Y	69	13.2	124.	3				
12	)		115Y	69	13.2	74.66	2	1-50.			
13	Idylwood-Fairfax Co.		230Y/115Y	Auto	12.8			1-150.			
14	Grottoes-Rockingham Co.		230Y/115Y	Auto	13.2	168.	1				
15	Lakeside-Henrico Co.		230Y/115Y	Auto	13.2	336.	2				
16	Lanexa-New Kent Co.		230Y/115Y	Auto	13.2	168.	1				
17	Lexington-Rockbridge Co.)		500Y/115Y	Auto		672.	6	1-112.			
18	)		115Y/138Y	Auto	13.2	112.	1	1-112.			
19	Locks-Dinwiddie Co.)		230Y/115Y	Auto	34.5	168.	1				
20	)		230Y/115Y	Auto	13.2	168.	1				
21	Loudoun-Loudoun Co.)		500Y/230Y	Auto		1680.	6				
22	)		230Y/115Y	Auto	13.2	336.	2				
23	Lowmoor-Alleghany Co.		138	13.2Y		80.	2				
24	Lynnhaven-City of Va. Beach		230/115	Auto	13.2	224.	1				
25	Northeast-Henrico Co.		230Y/115Y	Auto	13.2	168.	1				

Next Page is 427

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. Transmission

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation Virginia Con't (a)	*SEE ABOVE Character of Substation ø (b)	VOLTAGE - KV(E) Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	Northern Neck-Richmond Co.		115Y	13.2Y		89.6	2				
2	Northwest-Henrico Co.		230Y/115Y	Auto	13.2	336.	2				
3	Ox-Fairfax Co.		500Y/230Y	Auto	36.5	2520.	9				
4	Perth-Halifax Co.		115Y/69Y	Auto	24	20.	3				
5	Plaza-City of Richmond		230Y/115Y	Auto	13.2	168.	1				
6	Morrisville-Faquier Co.		500/230	Auto		268.8	3	1-89.6			
7	North Anna-Louisa Co.	Attended	500Y	22		2217.6	6	2-739.2			
8	Midlothian-Chesterfield	)	230/115	Auto		100.	1				
9		)	500/230	Auto	36.5	840.	3				
10	Portsmouth-City of Chesapeake	)Atd.	115Y	19.1		265.	1				
11		)	115Y	17.1		210.	1				
12		)	115Y	13.8		270.	4	1-40.			
13		)	115Y	13.2		22.4	1				
14		)	115	13.8Y		172.4	3				
15		)	230Y/115Y	Auto	13.2	224.	1				
16	Possum Point-Prince William Co.	)Atd.	230Y	25		1030.4	2				
17		)	230Y	20.9		297.	1				
18		)	115Y	13.8		135.	2				
19		)	115Y	13.2		160.002	6				
20		)	230Y/115Y	Auto	13.2	150.	1				
21		)	230	13.8		112.	2				
22											
23	Sewells Point-City of Norfolk		230Y/115Y	Auto	13.2	448.	2				
24	Shellbank-City of Hampton		230Y/115Y	Auto	13.2	224.	1				
25	Suffolk-City of Suffolk		230Y/115Y	Auto	13.2	224.	1				

Name of Respondent	This Report Is:	Date of Report	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

SUBSTATIONS *b. TRANSMISSION

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
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Line No.	Name and Location of Substation VIRGINIA CON'T (a)	*SEE ABOVE Character of Substation ø (b)	VOLTAGE - KV(E) Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	Surry-Surry Co.)	Atd.	500Y/230Y	Auto	36.5	900.	2				
2	)		500Y	22		1008.	3	1-336.			
3	)		230Y	22		1008.	3	1-336.			
4	)		230Y	13.2		56.	1				
5	Whealton-City of Hampton		230Y/115Y	Auto	13.2	336.	2				
6	Yorktown-York Co.)	Atd.	115Y	20.9		220.	2				
7	)		115Y	17.1		210.	1				
8	)		230/115		36.5	224.	1				
9	)		230	25		1030.4	2				
10	Yadkin-City of Chesapeake		500	230		840.	3	1-280.			
11	Valley-Augusta Co.		500	230		840.	3	1-280.			
12	Clifton Forge		138/115	Auto	13.2	50.	3	1-13.333			
13	Poe		230/115	Auto	34.5	168.	1				
14											
15											
16											
17											
18											
19											
20											
21											
22											
23											
24											
25											

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 82

SUBSTATIONS *b. Transmission

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	*SEE ABOVE Character of Substation ø (b)	VOLTAGE - KV(E) Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	NORTH CAROLINA										
2	Carolina-Halifax Co.		230Y/115Y	Auto	13.2	168.	1				
3	Earley's-Hertford Co.		230Y/115Y	Auto	13.2	168.	1				
4	Everetts-Martin Co.		230Y/115Y	Auto	13.2	150.	1				
5	Gaston-Halifax Co.		230Y	13.8		250.	2				
6	Roanoke Rapids-Halifax Co.	Attended	115Y	13.8		112.	2				
7	Tarboro-Edgecombe Co.		230Y/115Y			112.	1				
8	Winfall-Perquimans Co.		230Y/115Y	Auto	13.2	168.	1				
9	Shawboro-Currituck Co.		230Y/115Y	Auto	13.2	212.	2				
10											
11	Trowbridge-Washington Co.		230Y/115Y	Auto	13.2	168.	1				
12	Clubhouse		230/115	Auto	13.2	168.	1				
13	West Virginia										
14	Mt. Storm-Grant Co.)	Attended	500Y	20.9		1,140,000	6	1-190,000			
15	)		500Y	24		597,324	3				
16	)		500Y	4.16Y		40.	1				
17											
18											
19	TOTAL TRANSMISSION CAPACITY					34,623,009					
20											
21	ø ALL SUBSTATIONS ARE UNATTENDED EXCEPT AS NOTED										
22	(E) NOMINAL EQUIPMENT VOLTAGES										
23	* RESERVE STATION SERVICE										
24											
25											

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1982

ELECTRIC DISTRIBUTION METERS AND LINE TRANSFORMERS

1. Report below the information called for concerning distribution watt-hour meters and line transformers.
2. Include watt-hour demand distribution meters, but not external demand meters.
3. Show in a footnote the number of distribution watt-hour meters or line transformers held by the respondent under lease from others, jointly owned with others, or held otherwise than by reason of sole ownership by the respondent. If 500 or more meters or line transformers are held under a lease, give name of lessor, date and period of lease, and annual rent. If 500 or more meters or line transformers are held other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of accounting for expenses between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Item (a)	Number of Watt Hour Meters (b)	LINE TRANSFORMERS: Number (c)	LINE TRANSFORMERS: Total Capacity (In MVa) (d)
1	Number at Beginning of Year	1,470,829	399,908	16,243
2	Additions During Year			
3	Purchases	30,056	9,121	609
4	Associated with Utility Plant Acquired			
5	TOTAL Additions *(Enter Total of lines 3 and 4)*	30,056	9,121	609
6	Reductions During Year			
7	Retirements	22,663	7,468	368
8	Associated with Utility Plant Sold			
9	TOTAL Reductions *(Enter Total of lines 7 and 8)*	22,663	7,468	368
10	Number at End of Year *(Lines 1 + 5 - 9)*	1,478,222	401,561	16,484
11	In Stock	37,192	5,472	346
12	Locked Meters on Customers' Premises	28,423		
13	Inactive Transformers on System			
14	In Customers' Use	1,412,404	394,714	16,053
15	In Company's Use	203	1,375	85
16	TOTAL End of Year *(Enter Total of lines 11 to 15. This line should equal line 10.)* *	1,478,222	401,561	16,484

* Includes 2,058 watt hour meters and 1,271 line transformers which are a portion of property leased from Norfolk Southern Railway Company at Virginia Beach, Virginia. Lease dated March 1, 1930 and extends for 99 years. Annual rental $130,000. Non-associated company.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

ENVIRONMENTAL PROTECTION FACILITIES

1. For purposes of this response, environmental protection facilities shall be defined as any building, structure, equipment, facility, or improvement designed and constructed solely for control, reduction, prevention or abatement of discharges or releases into the environment of gaseous, liquid, or solid substances, heat, noise or for the control, reduction, prevention, or abatement of any other adverse impact of an activity on the environment.

2. Report the differences in cost of facilities installed for environmental considerations over the cost of alternative facilities which would otherwise be used without environmental considerations. Use the best engineering design achievable without environmental restrictions as the basis for determining costs without environmental considerations. It is not intended that special design studies be made for purposes of this response. Base the response on the best engineering judgement where direct comparisons are not available.

Include in these differences in costs the costs or estimated costs of environmental protection facilities in service, constructed or modified in connection with the production, transmission, and distribution of electrical energy and shall be reported herein for all such environmental facilities placed in service on or after January 1, 1969, so long as it is readily determinable that such facilities were constructed or modified for environmental rather than operational purposes. Also report similar expenditures for environmental plant included in construction work in progress. Estimate the cost of facilities when the original cost is not available or facilities are jointly owned with another utility, provided the respondent explains the basis of such estimations.

Examples of these costs would include a portion of the costs of tall smokestacks, underground lines, and landscaped substations. Explain such costs in a footnote.

3. In the cost of facilities reported on this page, include an estimated portion of the cost of plant that is or will be used to provide power to operate associated environmental protection facilities. These costs may be estimated on a percentage of plant basis. Explain such estimations in a footnote.

4. Report all costs under the major classifications provided below and include, as a minimum, the items listed hereunder:

A. Air pollution control facilities:
(1) Scrubbers, precipitators, tall smokestacks, etc.
(2) Changes necessary to accommodate use of environmentally clean fuels such as low ash or low sulfur fuels including storage and handling equipment
(3) Monitoring equipment
(4) Other.

B. Water pollution control facilities:
(1) Cooling towers, ponds, piping, pumps, etc.
(2) Waste water treatment equipment
(3) Sanitary waste disposal equipment
(4) Oil interceptors
(5) Sediment control facilities
(6) Monitoring equipment
(7) Other.

C. Solid waste disposal costs:
(1) Ash handling and disposal equipment
(2) Land
(3) Settling ponds
(4) Other.

D. Noise abatement equipment:
(1) Structures
(2) Mufflers
(3) Sound proofing equipment
(4) Monitoring equipment
(5) Other.

E. Esthetic costs:
(1) Architectural costs
(2) Towers
(3) Underground lines
(4) Landscaping
(5) Other.

F. Additional plant capacity necessary due to restricted output from existing facilities, or addition of pollution control facilities.

G. Miscellaneous:
(1) Preparation of environmental reports
(2) Fish and wildlife plants included in Accounts 330, 331, 332, and 335.
(3) Parks and related facilities
(4) Other.

5. In those instances when costs are composites of both actual supportable costs and estimates of costs, specify in column (g) the actual costs that are included in column (f).

6. Report construction work in progress relating to environmental facilities at line 9.

* Adjustments to correct for erroneous classification in 1981 of facilities as being placed in service rather than in construction work in progress.

( ) Denotes red figure. (Thousands of Dollars)

Line No.	Classification of Cost (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Additions (c)	Retirements (d)	* Adjustments (e)	Balance at End of Year (f)	Actual Cost (g)
1	Air Pollution Control Facilities	220,578	131		(21,879)	198,839	
2	Water Pollution Control Facilities	171,233	3,913		(67)	180,079	
3	Solid Waste Disposal Costs	18,153			(2,569)	15,584	
4	Noise Abatement Equipment	969				969	
5	Esthetic Costs	28,081	1,567	15		29,633	
6	Additional Plant Capacity						
7	Miscellaneous *(Identify significant)*						
8	TOTAL *(Total of lines 1 thru 7)*	439,014	10,611	15	(24,506)	425,104	
9	Construction Work in Progress	98,263				122,699	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Virginia Electric and Power Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1982

ENVIRONMENTAL PROTECTION EXPENSES

1. Show below expenses incurred in connection with the use of environmental protection facilities, the cost of which are reported on page 428. Where it is necessary that allocations and/or estimates of costs be made, state the basis or method used.
2. Include below the costs incurred due to the operation of environmental protection equipment, facilities, and programs.
3. Report expenses under the subheadings listed below.
4. Under item 6 report the difference in cost between environmentally clean fuels and the alternative fuels that would otherwise be used and are available for use.
5. Under item 7 include the cost of replacement power, purchased or generated, to compensate for the deficiency in output from existing plants due to the addition of pollution control equipment, use of alternate environmentally preferable fuels, or environmental regulations of governmental bodies. Base the price of replacement power purchased on the average system price of purchased power if the actual cost of such replacement power is not known. Price internally generated replacement power at the system average cost of power generated if the actual cost of specific replacement generation is not known.
6. Under item 8 include ad valorem and other taxes assessed directly on or directly relatable to environmental facilities. Also include under item 8 licensing and similar fees on such facilities.
7. In those instances where expenses are composed of both actual supportable data and estimates of costs, specify in column (c) the actual expenses that are included in column (b).

Line No.	Classification of Expense (a)	Amount (b)	Actual Expenses (c)
1	Depreciation	$15,137,000	
2	Labor, Maintenance, Materials, and Supplies Cost Related to Env. Facilities and Programs	6,324,000	
3	Fuel Related Costs		
4	Operation of Facilities	6,428,000	
5	Fly Ash and Sulfur Sludge Removal	2,053,000	
6	Difference in Cost of Environmentally Clean Fuels	5,727,000	(1)
7	Replacement Power Costs	1,683,000	
8	Taxes and Fees	2,141,000	
9	Administrative and General	1,162,000	(2)
10	Other *(Identify significant)*	794,000	
11	TOTAL	$42,449,000	

(1) The difference in fuel costs between alternative fuels is determined on the basis of 1982 deliveries.

(2) Includes air and emission monitoring at power stations and various studies regarding the biological, chemical and physical environment and thermal off-stream cooling.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Virginia Electric and Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1982

FOOTNOTE DATA

Page Number (a)	Item Number (b)	Column Number (c)	Comments (d)

INDEX

INDEX (Continued)

INDEX (Continued)

INDEX (Continued)

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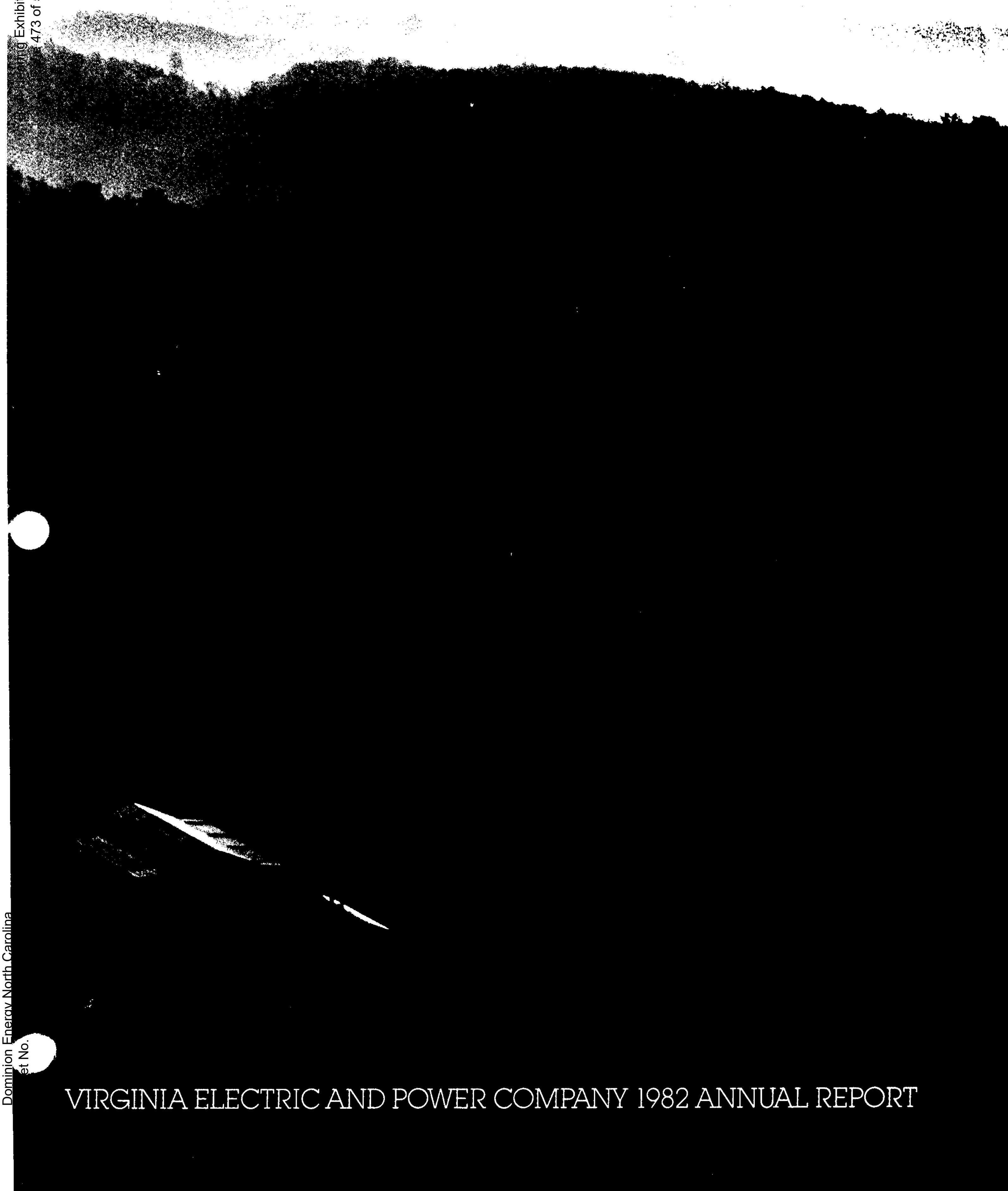
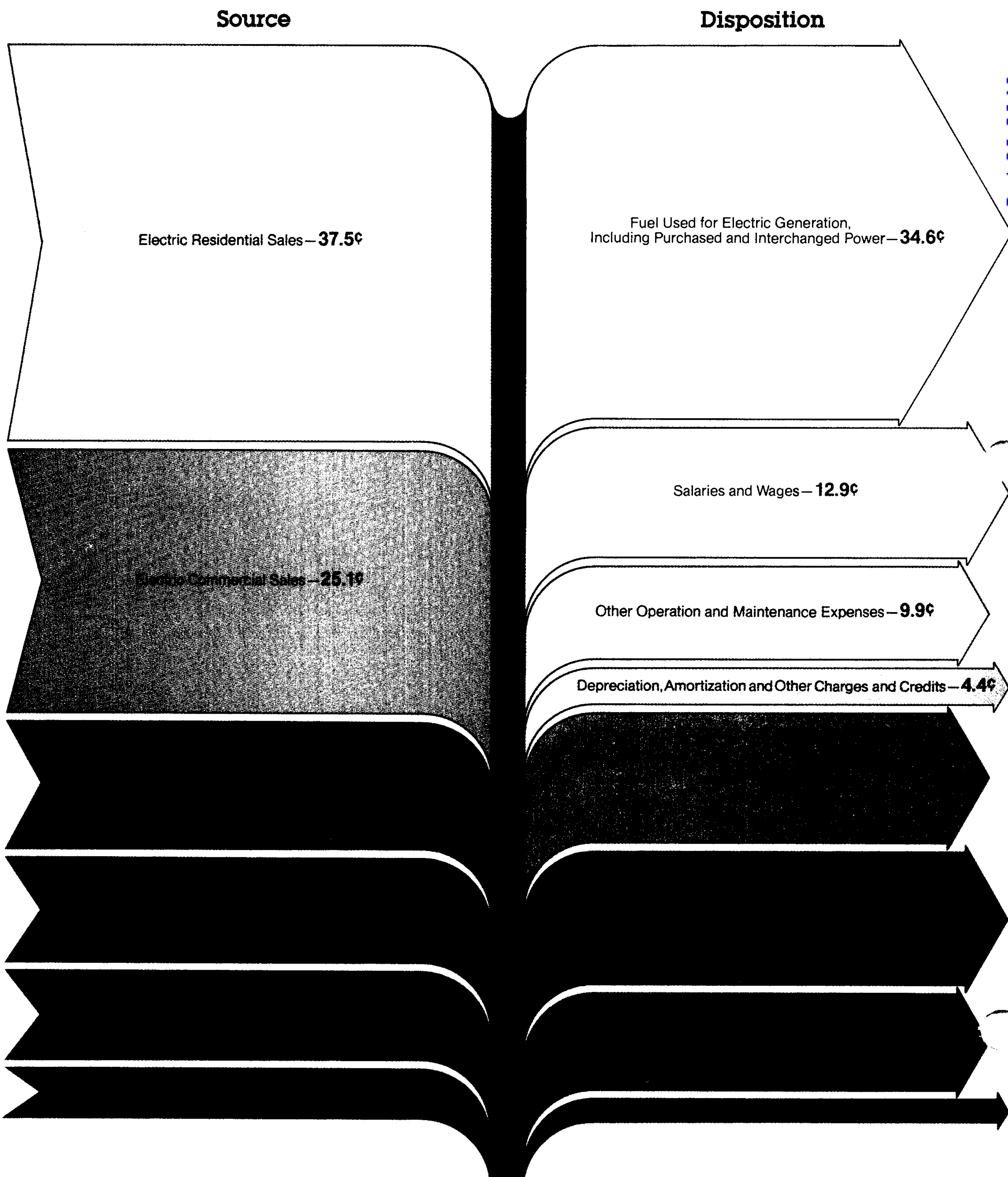


VIRGINIA ELECTRIC AND POWER COMPANY 1982 ANNUAL REPORT

Vepco's 32,000-square mile service area stretches from the Allegheny Mountains of West Virginia to the beaches of the Atlantic . . . and from the suburban communities outside Washington, DC to the farmlands of northeastern North Carolina. Its people and economy are as varied as its geography. Many of the photographs in this report illustrate the rich diversity of this region—its wide range of commercial and industrial opportunities, and the recreational advantages it offers in abundance.

Source and Disposition of the 1982 Revenue Dollar



1982 Highlights

	1982	1981	Increase (Decrease)	% Increase (Decrease)
Financial				
Total Operating Revenues	**$2,360,770,000**	$2,161,853,000	$198,917,000	9.2
Total Operating Expenses	**$1,855,174,000**	$1,693,221,000	$161,953,000	9.6
Net Income	**$ 278,589,000**	$ 237,780,000	$ 40,809,000	17.2
Balance Available for Common Stock	**$ 221,598,000**	$ 180,614,000	$ 40,984,000	22.7
Average Shares of Common Stock Outstanding	**112,062,000**	101,856,000	10,206,000	10.0
Stockholders—Common, Preferred and Preference	**230,200**	213,700	16,500	7.7
Earnings Per Share of Common Stock	**$1.98**	$1.77	$.21	11.9
Dividends Per Share of Common Stock	**$1.525**	$1.425	$.10	7.0
Book Value Per Share of Common Stock	**$18.31**	$18.64	$(.33)	(1.8)
Capital Expenditures	**$ 704,355,000**	$ 676,295,000	$ 28,060,000	4.1
Long-Term Financings	**$ 344,770,000**	$ 421,693,000	$(76,923,000)	(18.2)
Operations				
System Output—Megawatt-hours (thousands)	**42,854**	42,889	(35)	(0.1)
Year-End Capability—Megawatts	**11,117**	10,959	158	1.4
Service Area Peak Load—Megawatts	**8,879**	8,638	241	2.8
Customers—Electric—Heating	**372,044**	352,048	19,996	5.7
—Other	**1,033,356**	1,029,052	4,304	0.4
Total Electric	**1,405,400**	1,381,100	24,300	1.8
Customers—Gas	**123,400**	121,400	2,000	1.6
Average Residential Use—Electric—Kilowatt-hours	**10,641**	10,948	(307)	(2.8)
Employees—Full Time	**12,818**	11,487	1,331	11.6

Contents

Virginia Electric and Power Company • One James River Plaza • Richmond, Virginia 23261

To Our Stockholders

The company continued to improve its operating performance in 1982 and achieved increased earnings for the year. With the decision to cancel North Anna Nuclear Unit 3 in November 1982, significant progress also was made toward strengthening Vepco's long-term financial position.

For some time we have expressed confidence that the complex, costly programs that Vepco has undertaken to improve all phases of its operations would reap financial benefits.

That confidence was borne out in 1982.

Earnings increased 12 percent, rising from $1.77 per share in 1981 to $1.98 per share in 1982. Those positive results enabled the Board in October to increase the quarterly dividend by 2.5 cents per share to 40 cents per quarter, for an indicated annual rate of $1.60.

Increased Revenues

Although sales of electricity did not increase significantly in 1982, Vepco was able to achieve a substantial revenue increase by the effective use of a Virginia procedure that allowed rate increases to take effect four months earlier than in the past.

This procedure restricted rate increases to an amount limited to the increase in the Consumer Price Index and precluded any changes in the rate of return on equity and other elements of the rate structure.

While it will not always be advantageous, Vepco was able to use this procedure in 1982 to obtain a substantial increase in revenues that had a major direct impact on the improvement in earnings.

Energy Supply Mix

The earnings results in 1982 also were aided by our continuing shift away from oil to more economical coal and nuclear generation. Vepco's on-going coal conversion program, combined with major improvements in our fossil generation system and the overall excellent performance of our nuclear units, resulted in a better energy supply mix for the year.

Nuclear and coal units combined provided 78 percent of Vepco's total energy supply in 1982, up from 72 percent in 1981 and only 44 percent as recently as 1979. Oil's share of the total energy supply mix in 1982 was only 4 percent, down from 8 percent last year.

The improved energy supply mix allowed us to reduce our total fuel expenses, including purchased and interchanged power costs, by $28 million, from $845 million in 1981 to $817 million in 1982.

We are confident that our coal conversion projects and major programs to increase generating unit efficiency will continue to have important positive effects on future earnings. Those long-term positive effects will be increased by the cancellation of North Anna Unit 3.

North Anna Unit 3 Cancellation

On November 19, 1982, Vepco canceled construction of North Anna Unit 3. It was a painful but obviously necessary decision.

The most recent estimate of construction and financing costs for

T. Justin Moore, Jr., seated, and William W. Berry

North Anna Unit 3 showed those costs to be between $4.1 billion and $5.1 billion, compared to the previous estimate of $2.2 billion. This huge increase made construction of the unit economically unjustifiable.

The total approximate write-off on our North Anna Unit 3 investment will be $482 million.

In the long-term, the cancellation will have beneficial effects for both Vepco's stockholders and its customers.

The decision to cancel will:

- Avoid a financing requirement which would have been as much as $4.9 billion from 1983 through 1990 had the unit been built.
- Eliminate the need for enormous future stock sales, which would have caused serious dilution of current stockholders' equity.
- Keep Vepco's rates lower than they would be if the unit were completed, and allow for continued reliable electric service through the purchase of more economical capacity.

A more detailed discussion of the financial impacts of the cancellation is contained in the *Financial Results* section of this report.

Meeting Future Demand

Construction of the Pumped Storage Hydroelectric Project in th County, Virginia, was accelerated in 1982 and at year-end s approximately 65 percent complete. In April, we completed the sale of approximately 20 percent ownership interest to Allegheny Power System, Inc. (APS), with an option for APS to purchase up to a 50 percent interest in the project by the end of 1984.

Depending on APS' ultimate interest in the project, Vepco's share of the generating capacity will be between 1.05 million and 1.68 million kilowatts when the units come on the line in 1985-86.

This capacity, combined with economical purchases of other utilities' excess capacity to make up for the cancellation of North Anna Unit 3, will give us the means to meet projected demand growth through the early 1990s.

We also made substantial progress in 1982 on a major study of several conventional and various non-conventional means of meeting or reducing growth in power demand through the rest of the 1990s. This study will be completed by the end of 1984.

Reducing Financial Burden

The sale of a portion of the Bath County Project resulted in payments of $218 million from APS in 1982. These payments significantly reduced our financing requirements for the project in 1982. Based on a 20 percent interest in the project, APS' payments to Vepco will total about $272 million by the time the plant comes fully on line in 1986. The company also signed an agreement in December 1982, with the Old Dominion Electric Cooperative (ODEC) for the sale of a portion of North Anna Units 1 and 2. Based on a mid-1983 closing, Vepco will receive approximately $265 million from ODEC, of which $208 million will be paid at the closing.

Coal Pipeline

On September 2, 1982, Vepco signed an agreement with Transco Energy Company to pursue jointly development of a coal pipeline across Virginia. An independent study indicates that such a pipeline could reduce significantly coal transportation costs to Vepco's coal units and thereby provide additional savings in the company's fuel expenses. Transporting coal through the pipeline would increase pipeline coal's competitiveness in the export market and for all domestic users.

In addition to reducing coal transportation costs and providing benefits to the Virginia economy, the pipeline offers an opportunity for attractive returns on Vepco's investments. In 1982, Vepco and Transco actively sought changes in state and Federal laws which would permit development of a coal pipeline in Virginia. This effort is expected to continue in 1983.

Employee Relations

Vepco's long-standing commitment to provide its employees with competitive salaries, increased training opportunities and responsive management received an important vote of confidence in 1982. On July 28-29, Vepco's salaried employees voted not to be represented by either of two unions, making all the company's salaried employees union-free for the first time in 40 years. This was the second largest white collar union election in the history of the electric utility industry, and the largest such election in the last 42 years.

Chief Executive Transitions

Effective January 1, 1983, the title of Chief Executive Officer was transferred from Chairman of the Board T. Justin Moore, Jr., to President William W. Berry. At the same time, the title of Chief Operating Officer was shifted from Mr. Berry to Executive Vice President Jack H. Ferguson. With this action, Mr. Ferguson joins the Chairman and President in the Office of the Chief Executive.

Outlook

The past year was one of solid achievement. The success Vepco had in increasing its earnings in 1982 and the decisions it made to strengthen the company's long-term financial position point to continued progress in the future. The cancellation of North Anna Unit 3 will challenge our ability to improve on 1982's financial results in the short-term. But it was the right decision and will contribute significantly to Vepco's improved financial performance in the years to come.

T. Justin Moore, Jr.
Chairman of the Board

William W. Berry
President


North Carolina

Financial Results

Revenues

Vepco's operating revenues in 1982 totaled $2.4 billion, up $198.9 million, or 9 percent, over 1981. Our electric business generated $2,254.5 million, up 9 percent compared to 1981 and our gas business, Virginia Natural Gas, produced $106.2 million, a 15 percent increase over 1981.

Total electricity sales in 1982 were 40.0 billion kilowatt-hours, up 0.2 percent from 1981. The 1982 electricity sales included the effect of a planned reduction which came as the result of a phase out of wholesale power contracts of 11 municipal customers in North Carolina at the end of 1981.

Expenses

Total operating expenses in 1982 were $1.9 billion, up $162 million, or 10 percent, from 1981. Fuel expenses, in 1982, including purchased and interchanged power costs, were $817.3 million, down $27.7 million from 1981. The continuing reduction in oil usage due to our on-going oil-to-coal conversion program, combined with the increased efficiency of our fossil generation system, were the primary reasons for this reduction.

Earnings and Dividends

Earnings were up 21 cents per share, increasing from $1.77 in 1981 to $1.98 in 1982. The company paid its holders of common stock dividends of $1.525 per share in 1982 compared to $1.425 per share in 1981. In October 1982, Vepco increased the quarterly common stock dividend by 2.5 cents, raising the quarterly dividend from 37.5 cents to 40 cents, and the indicated annual rate to $1.60, compared to $1.50 per share in 1981.

The following table shows the company's high and low sales prices of common stock, principally traded on the New York Stock Exchange, and dividends paid for the last two years.

	1981			1982		
	High	Low	Dividends	High	Low	Dividends
First Quarter	11 ⅞	10 ⅛	$ .35	12 ⅞	11 ⅛	$ .37½
Second Quarter	12 ⅜	10 ⅝	.35	13 ⅝	12	.37½
Third Quarter	12 ½	10 ¾	.35	14 ⅝	12 ½	.37½
Fourth Quarter	13 ⅛	10 ⅛	.37½	15 ⅛	13	.40
			$1.42½			$1.52½

On December 31, 1982, there were 207,973 holders of record of the company's common stock.

Rate Results

Rate increases granted in 1982 by regulatory authorities and negotiated with governmental customers totaled $134.3 million on an annual basis.

- The Virginia State Corporation Commission granted a rate increase of $80.4 million under the Financial Operating Review procedure. This rate increase became effective on an interim basis on May 1, 1982, and was permanently approved by the commission on August 30, 1982.

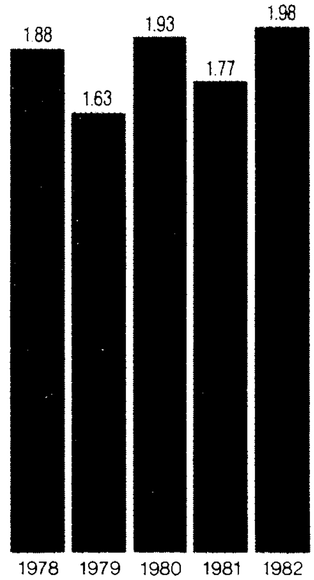
The company also requested that its allowed return on common equity in Virginia be increased from 15.0 to 15.5 percent, and requested an additional $13.8 million increase for that purpose. The commission did not approve this additional amount, but ruled that it would evaluate the company's generating unit performance at the next rate hearing to determine whether it would allow an increase in the allowed return on common equity.

- The North Carolina Utilities Commission granted a total rate increase of $11.8 million and authorized a significant increase in the company's allowed rate of return on common equity to 15.5 percent effective October 28, 1982.

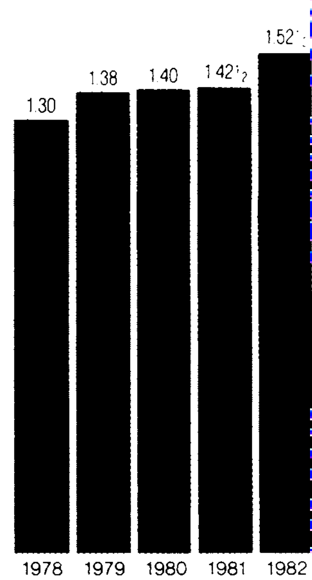
The commission's order made $3.6 million of the total increase effective September 6, 1982, and the remaining $8.2 million of the total increase effective October 28, 1982.

Exciting amusement parks such as Busch Gardens at Williamsburg, VA offer Vepco's service area interesting tourist attractions to strengthen its travel industry.

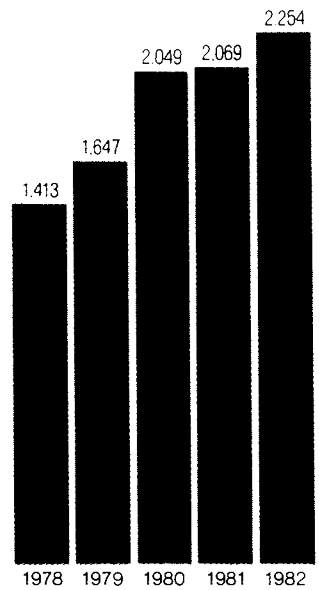
Earnings Per Share
Common Stock



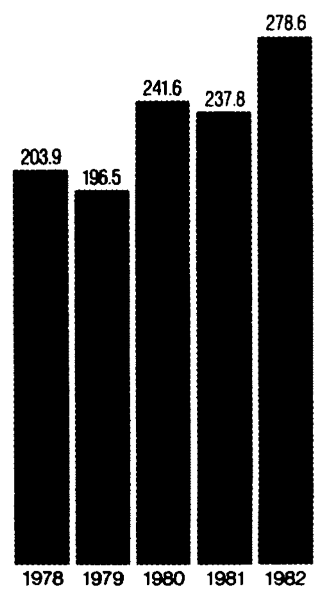
Dividends Paid Per Share



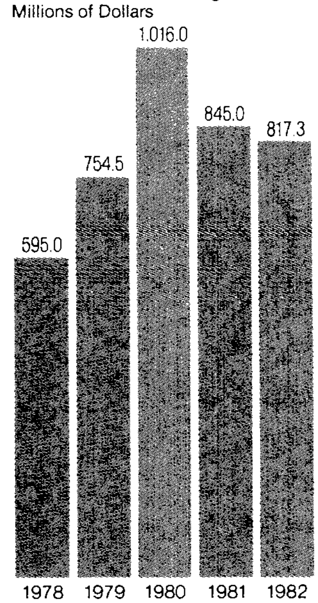
Electric Revenues
Millions of Dollars



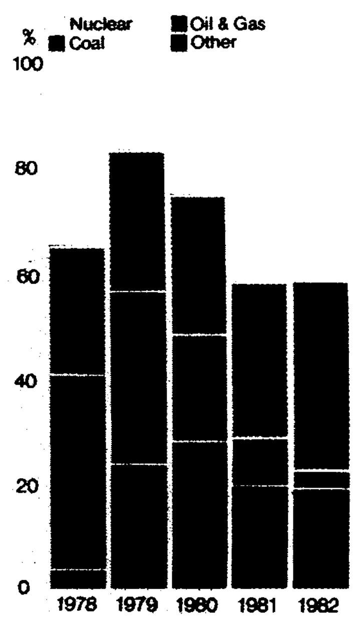
Net Income
Millions of Dollars

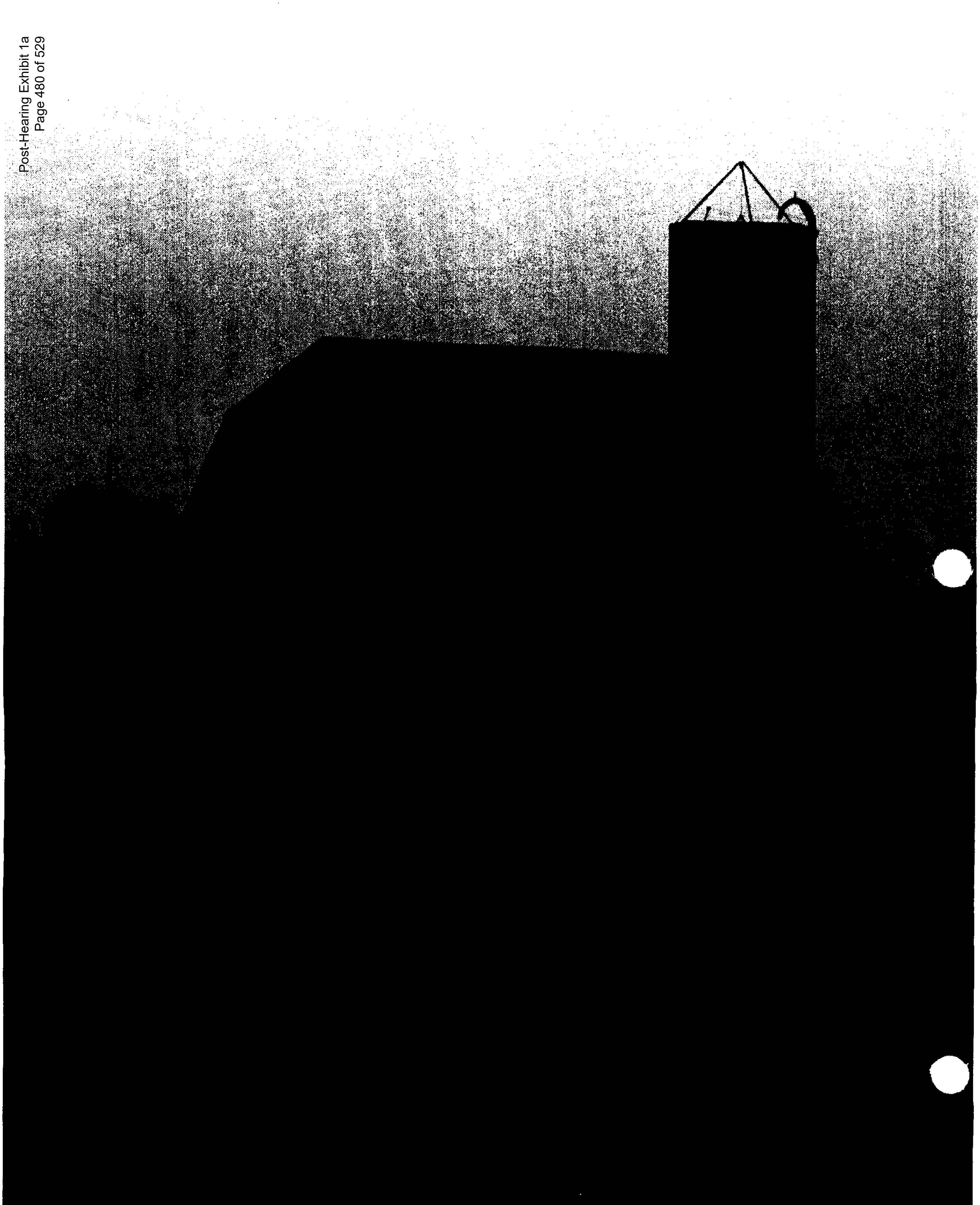


Fuel Expenses - Electric Including Purchased and Interchanged
Millions of Dollars



Sources of Generation





In 1981, the commission, citing deficiencies in the company's electric generating facilities, imposed a penalty on stockholders by reducing the authorized return on equity to 10.0 percent. The 1982 order issued by the commission abolished that penalty. The commission found that "Vepco has made remarkable strides in its operations. In fact we (the North Carolina Commission) find that Vepco is to be commended for its superior nuclear generation results."

- The West Virginia Public Service Commission approved an increase of $1.2 million, which became effective July 1, 1982. The commission authorized a 15.3 percent return on equity. Commission consideration of a subsequent request for an additional $2.2 million increase is pending.
- Federal Energy Regulatory Commission (FERC) on January 21, 1983, approved a settlement negotiated between Vepco and its wholesale municipal and cooperative customers in Virginia and North Carolina. The settlement provides for an increase in electric rates of $18.1 million, effective September 2, 1982.
- Vepco's electric rates to a number of state, county and municipal customers, and to Federal government agencies, are established by negotiation rather than by regulation.

Large Federal government customers, such as military installations and the General Services Administration, have agreed to abide by rate decisions by FERC for Vepco's wholesale customers. Accordingly, rates to those customers were placed into effect providing an annual increase of $6.8 million effective September 2, 1982.

- Vepco's rates for the National Aeronautics and Space Administration (NASA) are established by separate negotiations. Agreement with NASA was reached on May 1, 1982 for an annual increase of $500,000.
- The majority of Vepco's long-term contracts for electricity at very low rates with municipalities in Virginia expired by the end of 1982. These contracts have been renewed for three years at higher rates. Rate increases negotiated with all Vepco's Virginia municipal and county customers in 1982 resulted in additional annualized revenues of about $10 million.

Rate Requests

On February 7, 1983, Vepco filed a $18.7 million rate increase request with the North Carolina Utilities Commission.

In Virginia, we filed on January 31, 1983, for a $105.7 million fuel increase. We plan to file for a rate increase in Virginia and with FERC on March 31, 1983. The amount of these rate increases is still undetermined.

North Anna Unit 3 Cancellation

At year end, Vepco had expended approximately $570 million on the North Anna Unit 3 project.

The exact amount that must be written off is uncertain. That amount has been reduced by the use of certain parts and equipment in the operations of other generating units, and the sale of other parts and equipment. With those reductions, we now estimate the total write-off on our investment in North Anna Unit 3 will be approximately $482 million.

With cancellation, there was some negative impact on earnings in 1982 due to the cessation of Allowance For Funds Used During Construction (AFC) on the unit. AFC is a non-cash credit to income for financial reporting purposes.

But the reduction in external financing requirements afforded by the cancellation will result in higher future earnings per share despite the cessation of AFC.

Although the immediate effect of cancellation will be adverse, the long-term impact of cancellation will be beneficial both to stockholders and customers.

Cancellation will result in reductions in Vepco's external financing requirements, with the precise amounts dependent on regulatory treatment. Had Vepco continued with construction of the unit, the amount the company would have needed to raise through stock and bond sales for the unit would have totaled as much as $4.9 billion between 1983 and 1990.

Such enormous sales of stock would have caused serious dilution of stockholders' equity.

Moreover, this huge financing burden would have caused Vepco's ratio of earnings to fixed interest expense to decline to unacceptably low levels, possibly leading to downratings of the company's senior securities. If these securities were downrated, this would significantly increase the costs of capital required to be raised for all of Vepco's construction projects.

The net effect of the cancellation will be to strengthen Vepco's long-term financial position and eliminate a substantial barrier to increased earnings in the future.

Vepco has a goal of keeping its rate increases during the 1980s at or below increases in inflation. Thus far we have met that goal.

If North Anna Unit 3 were built, Vepco's rates, under present regulatory policy, would rise at a rate far above the expected increase in inflation.

Sunrise at the coal-fired Bremo Power Station as fog and low-lying clouds cling to the James River.

The ultimate impact of cancellation on rates will depend on regulatory decisions on our write-off. However, if we are allowed a fair recovery on our investment we estimate that we will achieve, or come very close to achieving, our price performance goals for the 1980s.

Daybreak on a traditional farm symbolizes the value of Virginia's agriculture in its many forms—from beef and dairy products to staple crops like tobacco and peanuts.


CROSS

Current Operations

Vepco continued its shift away from expensive oil to more economical coal and nuclear generation in 1982. This sustained improvement in the company's energy supply mix was primarily due to an aggressive oil-to-coal conversion program, coupled with increased efficiency of Vepco's coal units and the continued excellent performance of its nuclear units.

Coal units supplied 37 percent of the total energy supply mix in 1982, compared to 31 percent in 1981. This rise in coal's share of the energy supply mix reflected a 22 percent increase in coal unit generation, from 13 billion kilowatt-hours in 1981 to 16 billion kilowatt-hours in 1982.

Concurrently, Vepco's oil-fired generation decreased as a result of the company's on-going oil-to-coal conversion program. Oil accounted for only 4 percent of the energy supply mix in 1982, versus 8 percent in 1981.

Despite an extended refueling and maintenance outage at one of Vepco's four nuclear units, the nuclear share of the total energy supply mix in 1982 remained virtually unchanged from last year: 40.7 percent in 1982 compared to 41.5 percent in 1981. Vepco's nuclear units generated 17.4 billion kilowatt-hours in 1982, compared to 17.8 billion kilowatt-hours in 1981, a 2 percent decrease.

As a result of the continued improvement in the energy supply mix, Vepco was able to reduce its total fuel expenses, including purchased and interchanged power, in 1982 by $27.7 million—from $845.0 million in 1981 to $817.3 million in 1982.

Coal Conversions

On May 19, 1982, Portsmouth Unit 3 returned to service following conversion from oil to coal-firing. It is the seventh unit converted since the program began in 1975. To date, Vepco has converted a total of 1.8 million kilowatts of capacity from oil to coal, making this conversion program the largest in the country. Vepco's conversions represent approximately one-third of all those completed in the nation.

Vepco currently is planning to convert three more units with a total of 436,000 kilowatts of capacity by 1985. In addition, the company is evaluating the conversion of two more units with a total capacity of 202,000 kilowatts by 1987.

Electrostatic Precipitators

An important part of the conversion program is the installation of new, or upgrading of existing, electrostatic precipitators (ESP's) to control particulate emissions from the coal-fired units. These new or upgraded ESP's allow Vepco to operate its coal units at full power by ensuring that they do not exceed Federal emission standards. If those standards are exceeded, operating curtailments can be required.

The company completed ESP installations on Chesterfield Unit 4, Possum Point Unit 4, and Portsmouth Units 3 and 4 in 1982. New ESP's are scheduled for completion at Possum Point Unit 3 in 1983 and Chesterfield Unit 3 in 1984.

Coal Pipeline

To reduce future fuel expenses even further, Vepco in 1982 undertook initial steps to develop a coal pipeline across Virginia. The pipeline would have a mixture of ground coal and water that can be pumped through a pipe and later processed to allow the coal to be burned in coal-fired generation units.

Studies indicate that such a pipeline can reduce coal transportation costs from Western Virginia to Tidewater Virginia by between $5 and $11 per ton when compared to rail rates. These savings would significantly reduce Vepco's fossil generation fuel expenses in the future.

New energy-efficient industrial plants like the Consolidated Diesel Company near Whitakers, NC add to the diverse economy. Vepco works closely with state and local officials to help secure this type of resource for the region.

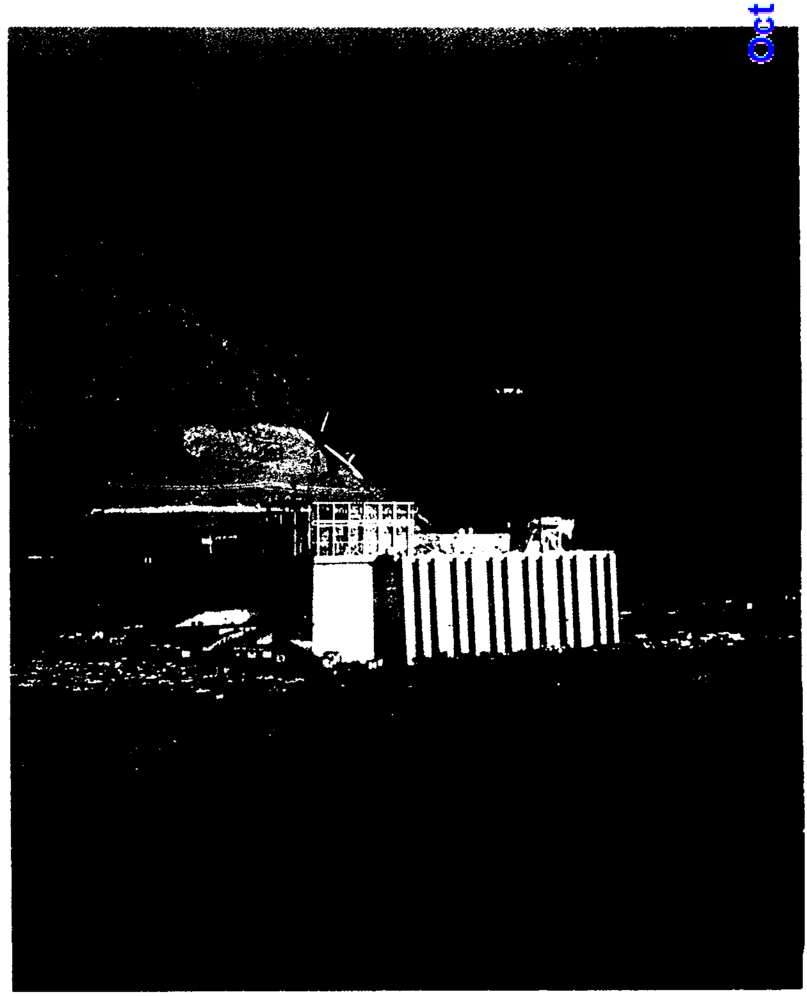
Fossil Station Operations

We are now about two-thirds of the way through a comprehensive, three-year program to upgrade our entire fossil steam generation system. Much of this effort is focused on our five major coal units: Chesterfield 5 and 6, and Mt. Storm 1, 2, and 3.

Under this program, Vepco has refurbished boilers, overhauled turbine generators, upgraded coal mills and refurbished coal handling equipment at the five major coal units. As a result, significant efficiency gains were achieved in 1982.

The average equivalent availability, or the percent of full power these units were able to produce, increased from 48 percent in 1981 to 64 percent in 1982.

The average heat rate of these five major coal units also improved dramatically in 1982. Heat rate is a measurement of the amount of heat (BTU's) needed to generate one kilowatt-hour of electricity. The less heat required, the less fuel used, and therefore the more efficient the unit is. Vepco's five major coal units



The powerhouse of the Bath County Pumped Storage Project now under construction. In the foreground is the excavation for the project's lower reservoir.

showed a 598 BTU per kilowatt-hour heat rate reduction in 1982 compared to 1981.

The improved performance of the five major coal units in 1982 was equally evident throughout Vepco's entire fossil steam generation system. Overall, the system equivalent availability increased from 65 percent in 1981 to 72 percent in 1982. Over the same period, fossil steam system heat rates declined by 4 percent, from 11,020 BTU's per kilowatt-hour in 1981 to 10,558 BTU's per kilowatt-hour in 1982.

Balanced Draft Conversions

A major element of the fossil unit improvement program is conversion of four large coal units from pressurized to balanced draft combustion. The conversions will increase these units' operating availability, significantly decrease future maintenance costs and greatly enhance working conditions in the plants.

On November 23, 1982, we completed conversion of Chesterfield Unit 5. Conversions of Chesterfield Unit 6 and Mt. Storm Units 1 and 2 are scheduled to be completed in 1983.

Laurel Run Mine

The Laurel Run Mine is very much a part of the improvement program since its production performance directly affects Vepco's Mt. Storm Power Station, which is adjacent to the mine.

The key improvement at Laurel Run is the longwall coal mining system which went into operation in September 1981. Production performance in 1982 increased about 72 percent over 1981, thus enabling production costs to be competitive with major suppliers in the area.

Nuclear Operations

Despite a prolonged refueling and maintenance outage at North Anna Unit 1, Vepco's four nuclear units in 1982 achieved a combined capacity factor of 60 percent. Capacity factor is a measure of a generating unit's productivity. A generating unit operating at full power every hour of the year would have a 100 percent capacity factor. This theoretical maximum cannot be achieved in practice because all generating units require periodic outages for maintenance and, in the case of nuclear units, refueling.

Vepco's two Surry nuclear units operated superbly in 1982. Both units achieved a capacity factor of 81 percent.

North Anna Unit 2 also operated well, achieving a 52 percent capacity factor for the year. On May 17, 1982, North Anna Unit 1 was taken out of service four days prior to a scheduled refueling and maintenance outage. During this outage, major repairs to portions of the reactor internals, steam generator tubing and reactor coolant piping system were necessary. These repairs were completed on November 3, 1982, and the unit was brought back on line on December 5, 1982. Almost immediately, however, a transformer failed and the unit's generator was damaged, causing a second outage which we estimate will end in early spring 1983. As a result of these outages, North Anna Unit 1 had only a 32 percent capacity factor in 1982.

Spent Nuclear Fuel

The company moved ahead in 1982 with plans to meet its spent nuclear fuel storage needs at the Surry Power Station. Vepco now intends to begin truck shipments of Surry spent nuclear fuel to the North Anna Power Station for temporary storage in the spring of 1984. In 1982, Vepco submitted several license applications to the Nuclear Regulatory Commission relative to those shipping plans, as well as a license application for a potential alternative plan—construction of a dry cask storage facility at Surry. The company also began litigation to overturn an ordinance in Louisa County, Virginia, where the North Anna Power Station is located. This ordinance prohibits storage of any spent nuclear fuel in the county, other than that generated by the North Anna Power Station. That litigation is continuing.

Transmission and Distribution

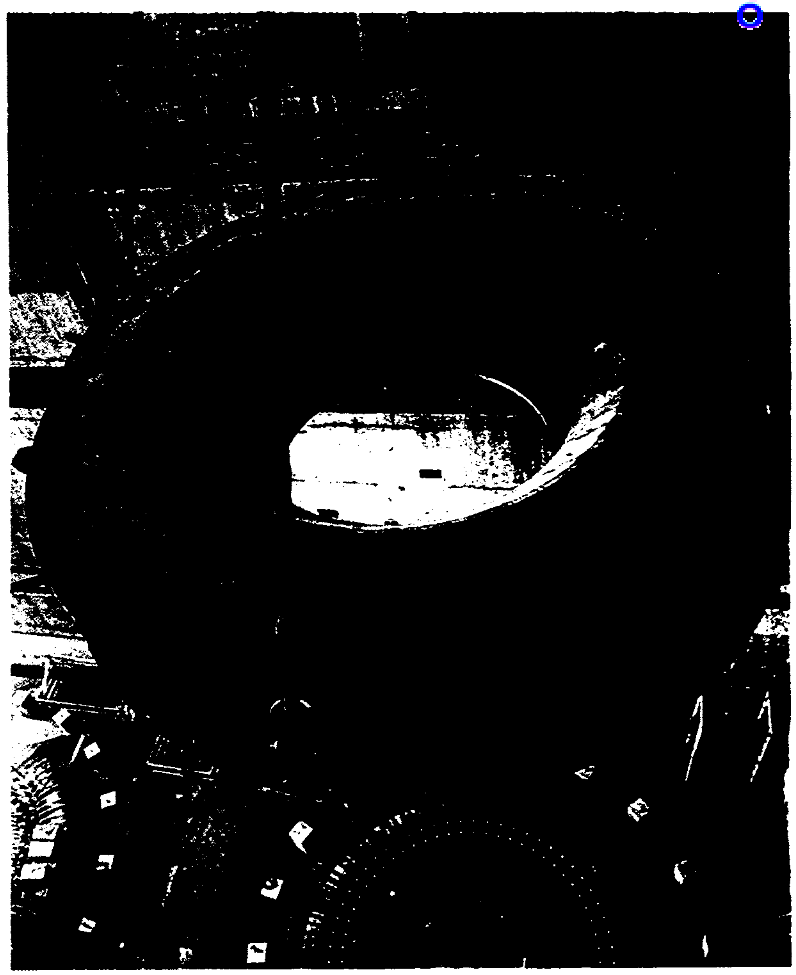
During 1982, the company began construction on two 500 KV transmission lines that will carry power from the Bath County Pumped Storage Project into the Vepco system. The lines go through the George Washington National Forest, where rugged terrain presents many engineering and construction challenges. In building these lines, Vepco is complying with stringent Federal regulations to ensure that there is minimal environmental impact on the forest.

Gas Exploration

The Virginia State Corporation Commission is considering Vepco's request to investigate the feasibility of natural gas exploration on about 10,000 acres of company-owned property in West Virginia. If approved, the natural gas exploration will be conducted by Virginia Nuclear, Inc., Vepco's exploration subsidiary. Sufficient amounts of natural gas have been discovered in the vicinity of Vepco's property to lead us to believe that exploration merits further investigation.

Price Performance

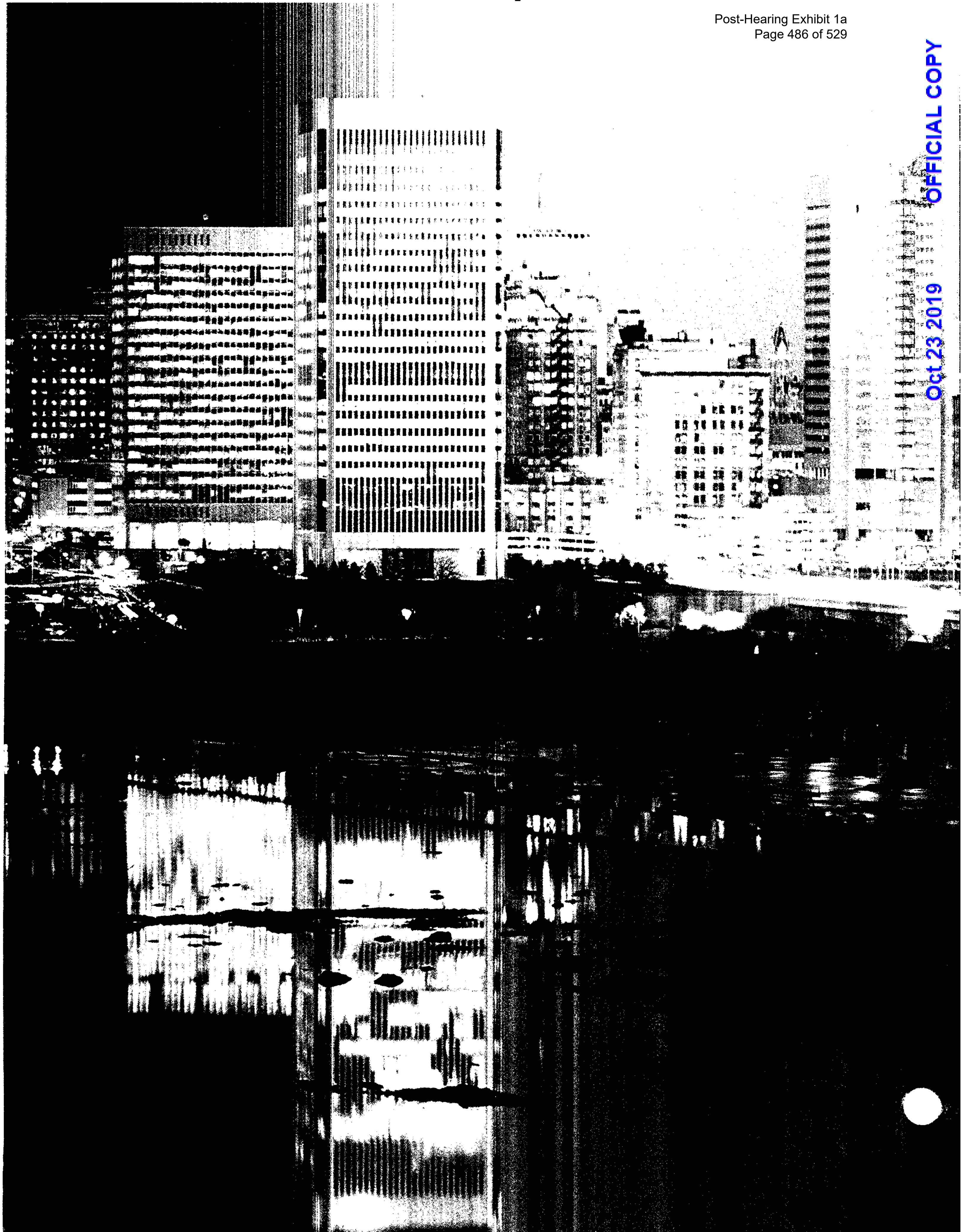
With the continuing shift away from oil-fired generation to less costly coal and nuclear units, Vepco's average residential price per kilowatt-hour was 6.68 cents in 1982. Since 1980, Vepco's average residential price per kilowatt-hour has increased 9 percent, compared to a 17 percent increase in the average rate of inflation as measured by the Consumer Price Index (CPI) over the same period.



A discharge ring is lowered into place in the Bath County Project powerhouse. The ring provides the foundation for the unit and will guide the flow of water discharging from the turbine.

Thus, Vepco is continuing to meet its goal of keeping its rate increases in line with, or below, the CPI over the decade of the 80s. This should have beneficial effects on Vepco's regulatory climate.

The Atlantic yields a rich harvest for the region's fishing industry, ranging from delicious seafoods to fertilizer and oil processed from catches of the famed menhaden fishing fleet.



Meeting Future Demand

In the summer of 1982, sustained periods of high temperatures did not occur in the Vepco service area as they had during the previous summer. As a result, the summer peak load of 8,490 megawatts (Mw) set on July 19, 1982, was 2 percent lower than the summer peak load of 8,638 Mw established on June 16, 1981. The 1982 winter peak demand of 8,879 Mw established on January 11, 1982 exceeded the 1981 winter peak by 428 Mw.

Vepco expects winter loads will grow more rapidly than summer loads because electric space heating, particularly the use of heat pumps, is expected to increase in our service area from its current level of 25 percent to approximately 38 percent in 1990. We believe this will produce a balance between summer and winter peaks by the mid-1980s, which should improve the load factor on our generating equipment.

Projected Peak Demand

Unless it is constrained by demand-reducing programs peak demand in the Vepco service area is expected to grow two to three percent annually through the mid-1990s. This will result in demand for electricity increasing by almost three million kilowatts in 1995, compared to 1982.

To help meet part of that projected increased demand, Vepco and Allegheny Power System, Inc. (APS) are building the world's largest pumped storage hydroelectric project in Bath County. In April 1982, Vepco sold an approximate 20 percent ownership interest in this project to APS, with an option to APS to increase its interest to up to 50 percent by the end of 1984. Depending on APS' ultimate participation in the project, Vepco's share of the generating capacity will be between 1.05 million and 1.68 million kilowatts.

The Bath County Project was approximately 65 percent complete at year end. Three of its six units are scheduled to go into service in 1985, with the remaining three units to come on line in the fall of 1986.

North Anna Unit 3 Cancellation

Capacity purchases may be necessary to make up for the loss of all or part of North Anna Unit 3's 907,000 kilowatts of capacity. These purchases are both possible and financially attractive, compared to the estimated $4,500 to $5,600 per kilowatt cost of building North Anna Unit 3.

Neighboring utilities have expressed an interest in selling capacity to Vepco, which was not available two years ago, reflecting slow economic growth which has flattened demand and left those utilities with excess capacity. That capacity should be available relatively economically because it was built with historical costs well below the cost of new construction.

With the Bath County Project and these purchases, Vepco will continue to meet its commitment to provide reliable supplies of electricity with adequate reserves through 1991.

Alternative Energy Sources

Begun in November 1981, Vepco's major Alternative Energy Sources study in 1982 focused primarily on means of fostering conservation, load management and cogeneration as ways to reduce or meet future demand.

The conservation techniques being studied include solar applications in homes and businesses, additional insulation for existing and new houses, and advanced forms of heat pumps and add-on heat pumps. Load management techniques being investigated are direct control of water heaters, heat pumps, and air conditioners, and industrial interruptible rates. Ways to increase cogeneration in Vepco's service area also are being reviewed.

At the same time, the study is investigating non-conventional fuels, such as peat, wood and wood waste products, and municipal solid waste. Concurrently, the study also is examining developing generation techniques, including fuel cells, coal gasification, photovoltaic cells and wind turbines.

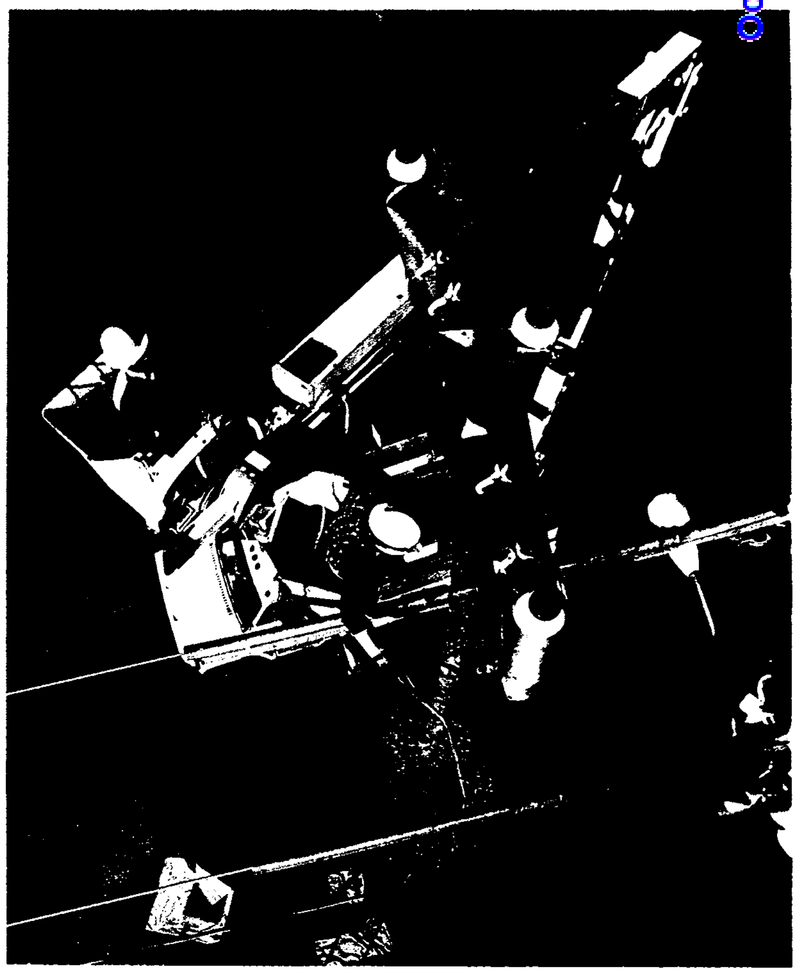
Ultimately, these non-conventional fuels and advanced generation techniques will be compared to one another and against conventional generation methods, such as coal units. The Alternative Energy study will be completed by the end of 1984. The results will enable Vepco to decide how projected demand through the 1990s can be met most economically.

Commercial Operations

Through its Economic Development and Energy Services Department, Vepco is vigorously pursuing programs which will help to reduce, or meet, future demand through load management, conservation and cogeneration.

A full-scale program to promote direct control of electric water heaters in the Norfolk area began in June 1982, and by year's end 15,000 customers were participating. A pilot project to study direct control by Vepco of air conditioners in Roanoke Rapids, North Carolina, and a program to foster the use of add-on heat pumps throughout the entire Vepco service area also were developed during the year.

Vepco also signed contracts with three cogenerators in 1982, adding a total of 65 Mw to the system. We expect to add two more cogenerators with a total of 24 Mw in the first quarter of 1983.



One of Vepco's maintenance and repair crews on the job.

In recent years, Vepco has implemented a vigorous program to improve meter-reading accuracy. As a result, the company achieved a meter-reading accuracy level of 99.6 percent on a monthly basis in 1982. The company also has created a program to improve the timeliness of service connections, with the result that 97 percent of all such connections were made on schedule in 1982.

Mirrored in the James River at dusk, the Richmond skyline represents the financial, marketing and commercial resources which are concentrated in several large urban centers of Vepco's service area.

Financial Support

In 1982, Vepco raised a total of $344.8 million in outside capital, including $66 million in term loans, $90 million in tax-exempt mortgage bonds, $0.8 million in Bath County Hydroelectric Trust funds and $188 million of common stock sales and subscriptions to finance its 1982 construction program.

The decision to cancel construction of North Anna Unit 3 will result in substantial reductions in Vepco's external financing requirements. The cancellation decision avoided an extremely difficult financing requirement. But Vepco also took positive steps in 1982 to reduce future financing needs through the sale of a portion of the Bath County Pumped Storage Project and completion of negotiations for the sale of a portion of the North Anna Power Station.

Bath County Project Sale

On April 27, 1982, Vepco received $194.3 million from Allegheny Power System, Inc. (APS) for the sale of approximately 20 percent of the ownership interest in Vepco's pumped storage hydroelectric project in Bath County.

This initial payment represented approximately 20 percent of the construction costs already incurred by Vepco on the project. Subsequent payments brought the total amount received from APS in 1982 to $218 million.

APS also will pay 20 percent of future construction costs, which will bring their total payments for 20 percent equity to an estimated $272 million by the time the project is completed in 1986.

Under the terms of the sale, APS also committed to purchase either an additional 20 percent ownership interest in the project, or an additional 20 percent of the project's generating capacity under a long-term contract. If APS chooses to purchase an additional 20 percent equity, the result will be a further reduction of approximately $300 million in Vepco's share of the project's costs.

Until the end of 1984, subject to further regulatory approvals, APS has the option of increasing its participation in the project to 50 percent.

North Anna Sale

In late 1981, Vepco and Old Dominion Electric Cooperative (ODEC) agreed in principle to the sale of a portion of the North Anna Power Station. Subsequent negotiations were held on the basis of ODEC purchasing a 12.5 percent ownership interest in each of North Anna Units 1 and 2, and North Anna Unit 3, then under construction, together with the common facilities, operating inventory and nuclear fuel and some ownership interest in support facilities and major spare parts.

Following the decision to cancel North Anna Unit 3, Vepco and ODEC signed an agreement on December 28, 1982, for the sale of portions of North Anna Units 1 and 2, and associated facilities. Based on a mid-year closing Vepco will receive approximately $265 million from ODEC, of which $208 million will be paid at the closing.

Stock Sales

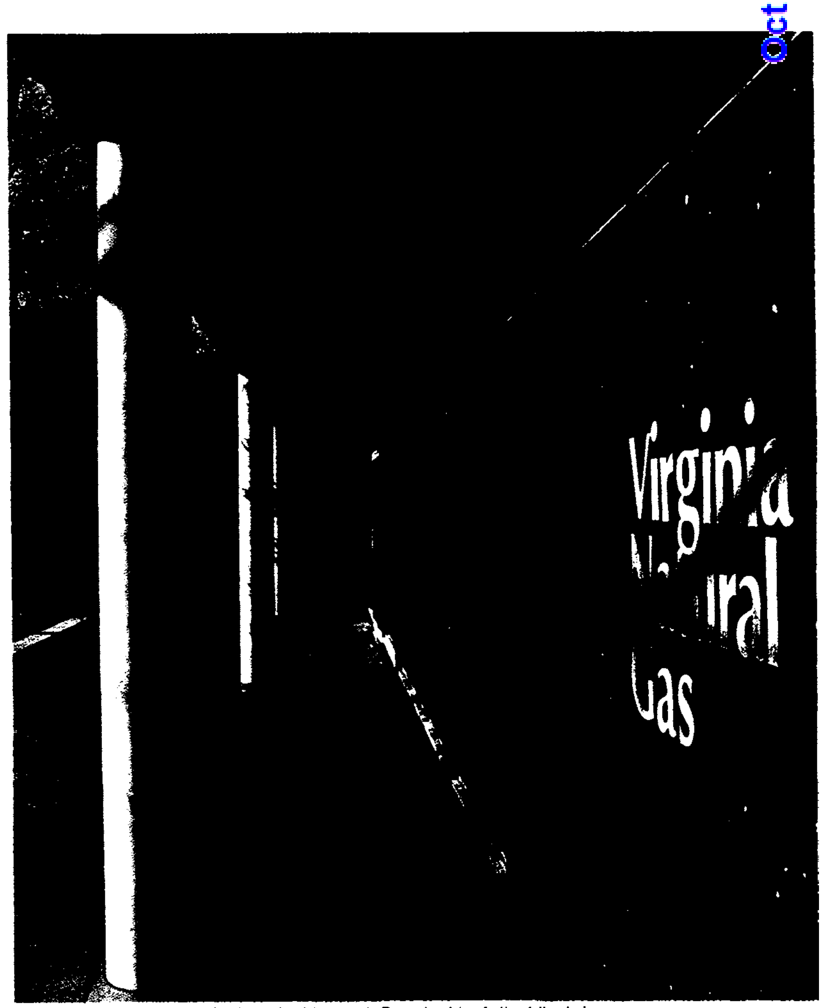
Vepco made two public offerings of common stock in 1982, one in February and the second in November. These offerings resulted in the sale of 10.5 million shares. Proceeds to the company were $132.4 million.

Customer Stock Purchase Plan

Subscriptions to the company's Customer Stock Purchase Plan increased to slightly more than $10.3 million in the third plan year (1982–83). Approximately 23,300 customers, an increase of 14 percent from the prior year, agreed to purchase Vepco common stock during the year beginning in September 1982 by making twelve monthly installment payments averaging $37.00.

Dividend Reinvestment Plan

At year end, more than 63,100 Vepco stockholders were participating in the company's dividend reinvestment plan. This was a 56 percent increase over participation in 1981. Vepco, along with others in the industry, was successful in its efforts to defeat attempts in the 97th Congress to repeal tax-deferred dividend reinvestment.



New headquarters of Virginia Natural Gas in Norfolk, Virginia.

Among the many natural resources reinforcing the region's economy are its Atlantic seaside resorts, with sunny strands like this pleasant scene along Virginia Beach.

Virginia Natural Gas

Virginia Natural Gas (VNG), Vepco's natural gas distribution division formed in late 1981, increased revenues in 1982 and took initial steps toward developing aggressive, new marketing programs in its Norfolk—Newport News service area.

Approximately 2,000 new customers were added during 1982 to the 121,400 customers VNG served in 1981. Sales in 1982 amounted to 18,809,000 mcf (thousand cubic feet) of gas, a 5 percent decrease from the previous year.

As a result of gas price adjustments due to continuing deregulation, VNG revenues in 1982 rose to $106.2 million, a 15 percent increase over 1981.

Marketing Programs

In 1982, VNG began a number of marketing programs to encourage customers to convert to natural gas for home, office and industrial use.

This initial effort will be expanded into a more comprehensive marketing program in 1983 to foster conversions from oil and propane, which, despite natural gas price increases, continue to be more costly fuels.

Yorktown Pipeline

A major accomplishment during the year was completion on March 25, 1982, of the eight-mile-long pipeline which delivers up to 42,000 mcf of gas per day to our Yorktown Power Station in Yorktown, Virginia. The pipeline was completed approximately two months ahead of schedule and at a cost of about $3 million, substantially under the original estimate of $5 million.

The pipeline serves Yorktown Unit 3, which was converted from being a unit capable solely of burning oil to one capable of burning oil or natural gas, or a combination of the two, on July 7, 1982. By burning both gas and oil, Yorktown Unit 3 now is available for rapid start up and can operate at overall lower fuel cost. This conversion also helps to reduce Vepco's oil usage.

Innovative Rate Design

In 1982, the company created and obtained approval from the Virginia State Corporation Commission (SCC) for a new, flexible natural gas rate for large-volume interruptible customers who use residual oil as an alternate fuel. This oil had declined in price to the point where it could be purchased for less than interruptible gas service.

The company designed a rate by which the price of large volumes of interruptible gas would track the price of residual oil based on the alternative fuel price established by the Federal government. This new, flexible rate resulted in four, large-volume, interruptible gas users, who had begun using residual oil, returning as customers of VNG. As a result, VNG was able to maintain the large volume of sales to these customers, thereby holding down costs for all of the division's gas customers.

Project HeatShare

In December 1982, VNG launched Project HeatShare, a program to assist needy persons with their heating bills. The program is funded with a grant from Vepco and tax-deductible voluntary contributions by VNG customers included in their January, February and March gas bill payments. Distribution of the project funds is administered by two Salvation Army units in the service area and at year's end there appeared to be considerable customer interest in the program.

Rate Case Results

On July 22, 1982, Vepco filed with the SCC a request to increase gas revenues by 4.8 percent overall. The request was based on raising revenues $4.9 million and was designed to provide a return on equity of 16.5 percent. On December 20, 1982, the SCC approved 73 percent of this request, allowing a 3.6 percent increase in revenues, or $3.7 million. As a result, the average residential customer's monthly bill increased by about 4.2 percent.

Gas Operating Statistics

	Years				
	1982	1981	1980	1979	1978
Operating revenues (thousands):					
Residential	**$ 49,372**	$ 42,036	$ 35,323	$ 29,380	$ 30,621
Commercial and industrial	**55,742**	49,539	34,411	25,346	20,000
Other	**1,130**	514	522	655	418
Total operating revenues	**$106,244**	$ 92,089	$ 70,256	$ 55,381	$ 51,039
Population served at retail-estimated	**992,000**	981,000	971,000	875,000	875,000
Number of customers:					
Residential	**114,056**	112,220	111,164	109,902	110,390
Commercial and industrial-firm	**9,348**	9,182	8,885	8,718	8,861
Interruptible	**70**	69	59	36	37
Total gas customers	**123,474**	121,471	120,108	118,656	119,288
Sales—Mcf (thousands)	**18,809**	19,738	17,495	16,307	15,303
Output—Mcf manufactured (thousands)	**156**	244	57	74	236
Mcf natural gas purchased (thousands)	**21,924**	20,755	18,906	17,499	16,407
Miles of main	**2,137**	2,123	2,108	2,095	2,096

1982 Financial Report

Virginia Electric and Power Company

Description of Business

The electric business of the Company is conducted in most of Virginia and in parts of North Carolina and West Virginia. In its service area, it sells electricity to retail customers (including governmental agencies) and, at wholesale, to rural electric cooperatives and municipalities. Virginia Natural Gas, a division of the Company, provides gas service in the Norfolk-Newport News area (except Portsmouth) and in the area extending from Newport News to and including Williamsburg.

Selected Financial Data

	Millions of Dollars (except per share amounts)				
	1982	1981	1980	1979	1978
Operating revenues	**$2,361**	$2,162	$2,120	$1,703	$1,465
Operating income	**506**	469	390	316	305
Balance available for common stock	**222**	181	184	141	150
Earnings per share of common stock	**1.98**	1.77	1.93	1.63	1.88
Dividends paid per share of common stock	**1.525**	1.425	1.40	1.38	1.30
Book value per share of common stock	**18.31**	18.64	18.63	18.65	19.09
Total assets	**7,359**	7,058	6,511	5,961	5,211
Net utility plant	**5,791**	6,013	5,586	5,229	4,686
Long-term debt and preferred stock subject to mandatory redemption	**3,411**	3,487	3,216	2,941	2,681

Management's Discussion and Analysis of Financial Condition and Results of Operations

LIQUIDITY. Liquidity for electric utilities like the Company, which have large amounts committed for construction projects, depends to a great extent on the ability to obtain outside funds, since charges to present customers are not designed to fund total construction costs for future generating capacity.

Internal cash generation during 1983 will be affected by the availability of the Company's nuclear generating units, the cost of fossil fuel or replacement power, the cost of funds used to finance capital expenditures and the outcome of rate proceedings.

With the cancellation of North Anna Unit 3 in November 1982 (see Note C to Financial Statements for additional information), the Company's capital expenditures and financing requirements will continue to decline.

In April 1982, the Company received approximately $194 million as initial payment for the sale of a portion of the Bath County Pumped Storage Project to Allegheny Power System, Inc. (APS). This payment also significantly reduced the Company's financing requirements. The Company will receive a total of approximately $300 million from APS by 1986 assuming APS's ownership interest in the project remains at approximately 20 percent (see Note G to Financial Statements for additional information).

CAPITAL RESOURCES. The 1983 capital requirements result principally from the estimated $780 million of capital expenditures and $110 million of refunding and mandatory cash sinking fund obligations of long-term debt and preferred stock. The Company presently expects that approximately 50% of these capital requirements will be obtained from internal sources and another 24% will be obtained from other sources (including the proceeds from the sale of a portion of the North Anna Station) while the remainder will be financed through sales of securities of various types. The objective is to achieve by the mid-1980's and to maintain capitalization ratios in the range of 50% long-term debt, 10% preferred and preference stock and 40% common equity.

Capital expenditures are generally financed initially by sales of commercial paper. To support these borrowings, the Company has available bank lines-of-credit amounting to $447 million.

Commercial paper is refunded by means of the sales of intermediate and long-term debt and equity securities. An earnings limitation of the Mortgage would have permitted the issuance at December 31, 1982, of $1,134 million of additional bonds assuming an interest rate of 13%. However, th issuance of additional bonds is limited to 60% of the net amount of certified additional property and at December 31, 1982, this limitation would have permitted the issuance of about $608 million of additional bonds. Another earnings limitation would permit 4 million additional shares of preferred stock to be issued assuming a dividend of $13.00.

The construction program and related expenditures and financings can continue to change as a result of, among other factors, higher than anticipated inflation, additional regulatory and environmental costs, further changes in the rate of growth in peak demand and licensing and construction delays.

The Company and Old Dominion Electric Cooperative (ODEC) agreed in principle, in late 1981, to the major terms of an arrangement for the purchase by ODEC of an ownership interest in the North Anna Station. On December 28, 1982, the Company and ODEC signed a final agreement which calls for ODEC to purchase 12.5 percent of North Anna Units 1 and 2, nuclear fuel and common facilities at the power station, and a portion of spare parts, inventory and other support facilities. In addition, ODEC will be responsible for 12.5 percent of all future expenditures on the facilities and for 12.5 percent of operating costs. The agreement is subject to the approval of five regulatory agencies. Based on a mid-1983 closing, the Company will receive approximately $265 million; $208 million will be paid at the time of closing and the remainder over the next 14 years.

RESULTS OF OPERATIONS. Due to the effects of infla tion, delays in obtaining a nuclear unit license, unscheduled outages of nuclear and coal fired units, major maintenance and repairs at most of the fossil units, increased depreciation and maintenance associated with additional power station units placed in service and increased costs of capital and capital expenditures, expenses other than fuel expenses have risen substantially during the past several years, and as a result, the Company has been granted substantial rate increases during these years.

After reflecting the gain on the sale of a portion of the Bath County Pumped Storage Project, additional revenues from rate increases, decreased fuel costs offset, in part, by the loss of allowance for funds used during construction due to the cancellation of North Anna Unit 3 and increased depreciation and amortization of abandoned project costs, the balance available for common stock increased $41.0 million from 1981 to 1982.

Electric revenues changed from 1980 through 1982 principally as a result of the following:

	Revenues Increase (Decrease) From Prior Year (Millions)	
	1982	1981
Rate increases and fuel cost recovery	**$179.5**	$(16.1)
Unit sales (excluding effect of above)	**1.7**	35.2
Other, net	**3.6**	1.1
Total	**$184.8**	$ 20.2

Gas revenues represent about 4.5% of total revenues. In 1981, the Company established Virginia Natural Gas, a new Gas Division. With the Company again permitted to connect new gas customers, gas revenues should continue to increase in the future as a result of increased sales and deregulation of natural gas pricing but not to a level that would be significant compared to electric operations.

Fuel and purchased and interchanged power expenses have declined over the years due to an improved energy supply mix resulting from the Company's ongoing oil-to-coal conversion program, major improvements in the fossil generation system and the increased usage of lower cost coal and nuclear generation. The average cost of fuel consumed per kilowatt-hour generated is shown below:

	Mills Per Kilowatt-hour		
	1982	1981	1980
Nuclear	**6.10**	6.52	8.09*
Coal—Mt. Storm (mine-mouth)	**18.12**	21.80	17.16
—Other	**21.46**	22.18	20.36
Oil	**56.32**	57.31	44.73
Total System	**15.03**	17.77	21.76

* Includes generation at North Anna Unit 2 priced at the cost of displaced fuel during preliminary operations. Actual costs were 6.19 mills per kilowatt-hour.

Kilowatt-hour output by energy source is shown below:

	1982	1981	1980
Nuclear	**41%**	41%	27%
Coal—Mt. Storm (mine-mouth)	**16**	13	13
—Other	**21**	18	12
Oil	**4**	8	19
Purchased and Interchanged	**16**	19	27
Other	**2**	1	2
	100%	100%	100%

To date the Company has converted a total of 1.8 million kilowatts of capacity from oil to coal and plans to convert three more units with a total of 436,000 kilowatts of capacity to coal by 1985. In addition, the Company is evaluating the conversion of two more units with a total capacity of 202,000 kilowatts by 1987.

Maintenance and depreciation expenses have increased since 1980 principally as a result of the addition of North Anna Unit 2 in December 1980, the Company's program for improvement of generating capability and increased costs for labor and materials.

Amortization of abandoned project costs increased due to the amortization associated with the cancellation of the construction of North Anna Unit 4. The Unit was canceled in November 1980 and the Company began amortizing the costs in September 1981.

For information with respect to *Federal income and other taxes*, see Notes B and D to Financial Statements.

Other income—miscellaneous, net and *associated taxes* in 1981 reflects the termination of contracts for electricity with the North Carolina municipal customers (see Note O to Financial Statements) and in 1982 reflects the gain on the sale of a portion of the Bath County Pumped Storage Project (see Note G to Financial Statements).

Allowance for funds used during construction (AFC) for other (equity) funds decreased in 1981 principally as a result of the cancellation of construction of North Anna Unit 4 in November 1980 and the placing in service of North Anna Unit 2 in December 1980. As a result of approval by the Virginia Commission to discontinue AFC for Virginia jurisdictional customers on all new projects commenced after September 1981 (this reduction of AFC has been reflected in increased Virginia jurisdictional rates) and the cancellation of the construction of North Anna Unit 3 in November 1982, the amounts accrued in future years should decline further.

Continuation of the Company's capital expenditures program and the related financing, together with increases in construction and nuclear fuel costs and changes in internally generated funds and costs of capital, have resulted in changes in the amounts of *interest charges*.

INFLATION. From the mid-1940's until the early 1970's customer demand increased so rapidly that the cost per kilowatt-hour to the customer declined. With the persistent high rates of inflation and rapid rises in oil costs during the 1970's, and a significant decrease in the rate of growth of demand, the Company has required substantial amounts of rate relief including increases in fuel cost recovery billings.

An estimate of the effect of inflation measured by constant dollar accounting and current cost accounting for selected financial data is presented in Note P to Financial Statements.

Report of Management

The management of Virginia Electric and Power Company is responsible for all information and representations contained in the financial statements and other sections of the annual report. The financial statements, which include amounts based on estimates and judgments of management, have been prepared in conformity with generally accepted accounting principles. Other financial information in the annual report is consistent with that in the financial statements.

Management maintains a system of internal accounting control designed to provide reasonable assurance at a reasonable cost that the Company's assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. This system includes written policies, an organizational structure designed to ensure appropriate division of responsibilities, careful selection and training of qualified personnel and a program of internal audits.

The financial statements have been examined by Coopers & Lybrand, independent certified public accountants. Their examination is conducted in accordance with generally accepted auditing standards and includes a review of the Company's accounting systems, procedures and internal controls, and the performance of tests and other auditing procedures sufficient to provide reasonable assurance that the financial statements neither are materially misleading nor contain material errors.

The Audit Committee of the Board of Directors, composed entirely of directors who are not officers or employees of the Company, meets periodically with the independent auditors, the executive manager-internal auditing and management to discuss auditing, internal accounting control and financial reporting matters and to ensure that each is properly discharging its responsibilities. Both the independent auditors and the executive manager-internal auditing periodically meet alone with the Audit Committee and have free access to the Committee at any time.

VIRGINIA ELECTRIC AND POWER COMPANY

Report of Independent Certified Public Accountants

To the Stockholders and Board of Directors of Virginia Electric and Power Company:

We have examined the balance sheets of Virginia Electric and Power Company as of December 31, 1982 and 1981, and the related statements of income, earnings reinvested in business and changes in financial position for each of the three years in the period ended December 31, 1982. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

As discussed in Note C to FINANCIAL STATEMENTS, the Company has canceled plans to construct North Anna Unit 3. At this time, it is uncertain how much of the amount deferred relating to the cancellation and any subsequent cancellation costs will be recoverable.

In our opinion, subject to the effects on the 1982 financial statements of such adjustments, if any, as might have been required had the outcome of the uncertainty referred to in the preceding paragraph been known, the financial statements referred to above present fairly the financial position of Virginia Electric and Power Company as of December 31, 1982 and 1981, and the results of its operations and the changes in its financial position for each of the three years in the period ended December 31, 1982, in conformity with generally accepted accounting principles applied on a consistent basis.

Coopers & Lybrand

New York, New York
February 4, 1983

COOPERS & LYBRAND

Virginia Electric and Power Company
Statements of Income

	For The Years Ended December 31,		
	1982	1981	1980
	(Thousands, except per share amounts)		
Operating revenues (Notes A and L):			
Electric	**$2,254,526**	$2,069,764	$2,049,518
Gas	**106,244**	92,089	70,256
Total	**2,360,770**	2,161,853	2,119,774
Operating expenses:			
Operation:			
Fuel used in electric generation (Notes A and E)	**542,712**	555,466	674,996
Purchased and interchanged power (Note N)	**274,568**	289,558	341,011
Other (Note E)	**368,418**	309,147	250,848
Maintenance (Note A)	**169,564**	138,147	123,962
Depreciation (Notes A and F)	**190,960**	174,120	145,032
Amortization of abandoned project costs (Note C)	**21,221**	12,203	6,933
Taxes—Federal income (Notes A and B)	**152,918**	93,669	70,004
—Other (Note D)	**134,813**	120,911	117,456
Total	**1,855,174**	1,693,221	1,730,242
Operating income	**505,596**	468,632	389,532
Other income:			
Allowance for other funds used during construction (Note A)	**43,863**	44,264	73,206
Miscellaneous, net (Notes G and O)	**25,457**	16,236	2,973
Income taxes associated with miscellaneous, net (Note B)	**(14,776)**	(7,607)	(550)
Total	**54,544**	52,893	75,629
Income before interest charges	**560,140**	521,525	465,161
Interest charges:			
Interest on long-term debt	**296,225**	280,012	234,561
Other	**24,836**	44,276	28,530
Allowance for borrowed funds used during construction (Note A)	**(39,510)**	(40,543)	(39,550)
Total	**281,551**	283,745	223,541
Net income	**278,589**	237,780	241,620
Preferred and preference dividend requirements	**56,991**	57,166	57,291
Balance available for common stock	**$ 221,598**	$ 180,614	$ 184,329
Shares of common stock—average for year	**112,062**	101,856	95,520
Earnings per share of common stock	**$1.98**	$1.77	$1.93
Cash dividends paid per common share	**$1.525**	$1.425	$1.40

( ) Denotes red figure.
The accompanying notes are an integral part of the financial statements.

Virginia Electric and Power Company
Balance Sheets

Assets

	At December 31,			
	1982		1981	
(Thousands)				
UTILITY PLANT (Note A):				
Electric		**$6,979,805**		$7,032,549
Gas		**85,141**		75,949
Common		**21,920**		22,918
Total (includes $1,196,297 plant under construction (Note G) [1981—$1,616,880])		**7,086,866**		7,131,416
Less accumulated depreciation (Notes A and F)		**1,421,849**		1,263,867
		5,665,017		5,867,549
Nuclear fuel (less accumulated amortization of $271,497 [1981—$210,879]) (Note A)		**126,027**		145,339
Net utility plant		**5,791,044**		6,012,888
INVESTMENTS:				
Nonutility property at cost or written-down amounts (less allowance of $6,678 [1981—$7,657])		**6,254**		5,472
Subsidiary companies at equity (includes advances of $12,128 [1981—$14,758])(Note A)		**21,257**		21,282
Net investments		**27,511**		26,754
CURRENT ASSETS:				
Cash (Note J)		**15,440**		16,669
Temporary cash investments		**7,000**		
Accounts receivable:				
Customers	**$208,878**		$186,665	
Other	**7,912**		25,560	
	216,790		212,225	
Less allowance for doubtful accounts	**2,343**	**214,447**	2,002	210,223
Accrued unbilled revenues		**82,539**		93,551
Materials and supplies at average cost or less:				
Plant and general (including construction materials)	**141,359**		76,924	
Fossil fuel	**125,281**	**266,640**	129,557	206,481
Prepayments:				
Taxes	**25,206**		28,964	
Other	**15,186**	**40,392**	18,712	47,676
Total current assets		**626,458**		574,600
DEFERRED DEBITS AND OTHER ASSETS:				
Abandoned project costs (less accumulated amortization of $57,582 [1981—$36,361])(Note C)		**628,419**		193,112
Deferred fuel costs (Note A)		**123,235**		137,000
Deferred interest (Note A)		**29,328**		22,740
Pollution control project funds		**22,149**		37,667
Nuclear fuel progress payments (Note A)		**50,067**		22,803
Unamortized expense on debt		**8,200**		8,971
Other		**52,945**		21,296
Total deferred debits and other assets		**914,343**		443,589
		$7,359,356		$7,057,831

The accompanying notes are an integral part of the financial statements.

Capital and Liabilities

(Thousands)	At December 31, 1982	1981
PREFERRED STOCK SUBJECT TO MANDATORY REDEMPTION (Note H)	**$ 321,944**	$ 326,927
PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION (Note I)	**289,014**	289,014
PREFERENCE STOCK NOT SUBJECT TO MANDATORY REDEMPTION (Note I)	**57,360**	57,360
COMMON STOCKHOLDERS' EQUITY:		
Common stock—no par (Note I)	**1,645,829**	1,457,072
Other paid-in capital	**23,680**	24,516
Earnings reinvested in business, as annexed	**519,187**	470,888
Total common stockholders' equity	**2,188,696**	1,952,476
LONG-TERM DEBT (Note K)	**3,089,041**	3,160,014
CURRENT LIABILITIES:		
Securities due within one year (Notes H and K)	**109,931**	94,983
Loans payable, pending permanent financing (Note J)	**103,333**	164,938
Accounts payable, trade	**100,394**	87,742
Due to banks	**37,367**	30,394
Customer deposits	**21,775**	14,424
Payrolls accrued	**21,656**	16,611
Taxes accrued	**69,060**	74,730
Interest accrued	**80,644**	83,192
Deferred income taxes (Note B)	**11,525**	14,313
Other	**47,023**	58,869
Total current liabilities	**602,708**	640,196
DEFERRED CREDITS:		
Uranium settlement (Note N)	**158,122**	160,914
Accumulated deferred income taxes (Notes A and B):		
Liberalized depreciation	**254,773**	203,714
Abandoned project costs	**199,527**	73,384
Other	**30,758**	34,591
Deferred investment tax credits (Notes A and B)	**103,409**	109,647
Other (Note E)	**64,004**	49,594
Total deferred credits	**810,593**	631,844
COMMITMENTS AND CONTINGENCIES (Note N)		
	$7,359,356	$7,057,831

Virginia Electric and Power Company
Statements of Earnings Reinvested in Business

	For The Years Ended December 31,		
	1982	1981	1980
		(Thousands)	
Balance at beginning of year	**$470,888**	$435,430	$384,600
Net income (see "Statements of Income")	**278,589**	237,780	241,620
Total	**749,477**	673,210	626,220
Cash dividends:			
Preferred stock subject to mandatory redemption:			
Series:			
$7.325	**5,128**	5,128	5,128
$8.40	**6,720**	6,720	6,720
$9.125	**1,734**	1,807	1,825
$8.20	**4,920**	4,920	4,920
$8.60	**2,985**	3,087	3,189
$8.625	**3,191**	3,191	3,191
$8.925	**2,499**	2,499	2,499
Preferred stock not subject to mandatory redemption:			
Series:			
$5.00	**533**	533	533
$4.04	**52**	52	52
$4.20	**62**	62	62
$4.12	**134**	134	134
$4.80	**351**	351	351
$7.72	**2,702**	2,702	2,702
$8.84	**3,094**	3,094	3,094
$7.45	**2,980**	2,980	2,980
$7.20	**3,240**	3,240	3,240
$7.72 (1972 Series)	**3,860**	3,860	3,860
$9.75	**5,850**	5,850	5,850
Preference stock not subject to mandatory redemption	**6,960**	6,960	6,960
Common stock	**172,791**	144,937	133,005
Total dividends	**229,786**	202,107	190,295
Other deductions, net	**504**	215	495
Balance at end of year	**$519,187**	$470,888	$435,430

The accompanying notes are an integral part of the financial statements.

Virginia Electric and Power Company
Statements of Changes in Financial Position

	For The Years Ended December 31, 1982	1981	1980
	(Thousands)		
SOURCE OF FUNDS:			
Funds provided by operations:			
Net income	**$ 278,589**	$ 237,780	$ 241,620
Items not affecting working capital:			
Provision for depreciation (Notes A and F)	**190,960**	174,120	145,032
Amortization of nuclear fuel (Note A)	**60,618**	79,558	52,170
Amortization of abandoned project costs (Note C)	**21,221**	12,203	6,933
Allowance for other funds used during construction (Note A)	**(43,863)**	(44,264)	(73,206)
Allowance for borrowed funds used during construction (Note A)	**(39,510)**	(40,543)	(39,550)
Deferred income taxes (Notes A and B)	**171,491**	72,226	52,177
Deferred investment tax credits, net (Notes A and B)	**(10,110)**	6,711	6,627
Gain (pre-tax) on sale of a portion of the Bath County Pumped Storage Project (Note G)	**(16,523)**		
Total funds provided by operations	**612,873**	497,791	391,803
Funds provided by financing and other sources:			
Mortgage bonds (Note K)	**90,000**	138,000	75,000
Common stock (Note I)	**187,920**	55,353	79,064
Bath County hydroelectric trust (Note K)	**850**	47,340	201,810
Term notes (Note K)	**66,000**	181,000	125,000
(Increase) decrease in pollution control project funds	**15,518**	7,903	(37,734)
(Increase) decrease in deferred fuel costs (Note A)	**13,765**	(58,896)	11,146
Sale of a portion of the Bath County Pumped Storage Project (includes option payments) (Note G)	**198,217**		
Total funds provided by financing and other sources	**572,270**	370,700	454,286
	$1,185,143	$ 868,491	$ 846,089
APPLICATION OF FUNDS:			
Utility plant expenditures—net of retirements (excluding AFC)	**$ 582,439**	$ 542,331	$ 536,049
Nuclear fuel (excluding AFC)	**38,543**	49,157	32,315
Abandoned project costs (Note C)	**13,253(a)**	32,595	1,332(a)
Dividends on common, preferred and preference stocks	**229,786**	202,107	190,295
(Increase) decrease in loans payable	**61,605**	(81,217)	48,009
(Increase) decrease in uranium settlement (Note N)	**2,792**	(18,742)	(11,826)
Increase (decrease) in nuclear fuel progress payments (Note A)	**27,264**	18,615	(713)
Increase in deferred interest (Note A)	**6,588**	2,922	5,357
Securities reacquired or repaid	**217,199**	124,276	65,300
Increase (decrease) in working capital other than loans payable	**(4,669)**	8,339	(31,757)
Other, net	**10,343(a)**	(11,892)	11,728
	$1,185,143	$ 868,491	$ 846,089
Changes in the individual amounts comprising working capital other than loans payable were as follows:			
Accounts receivable	**$ 4,224**	$ 9,788	$ 38,537
Uranium settlement (Note N)			(41,000)
Accrued unbilled revenues	**(11,012)**	10,428	(10,679)
Materials and supplies	**12,801(a)**	20,763	14,047
Accounts payable, trade	**(12,652)**	23,932	16,010
Due to banks	**(6,973)**	(30,394)	
Taxes accrued	**5,670**	(21,124)	(27,843)
Interest accrued	**2,548**	(6,691)	(7,217)
Deferred income taxes (Note B)	**2,788**	543	2,460
Other, net	**(2,063)**	1,094	(16,072)
	$ (4,669)(b)	$ 8,339(b)	$ (31,757)(b)

(a) Does not include reclassification in 1982 from construction work in progress (CWIP) to abandoned project costs, materials and supplies, and related AFC included in other, net of $443,275, $47,359 and $21,154, respectively. Abandoned project costs in 1980 does not include reclassification from CWIP of $122,369.

(b) Does not include reclassification as current liabilities of maturing long-term debt and cash sinking fund obligations of debt and preferred stock as follows: 1982—$109,931; 1981—$94,983; and 1980—$124,276.

The accompanying notes are an integral part of the financial statements.

Notes to Financial Statements

A. Significant Accounting Policies:

General:
The Company's accounting practices are prescribed by the Uniform Systems of Accounts promulgated by the regulatory commissions having jurisdiction.

Revenues:
Operating revenues are recorded on the basis of service rendered.

Utility Plant and Depreciation:
Utility plant is recorded at original cost which includes labor, materials, services, allowance for funds used during construction and other indirect costs. The cost of depreciable utility plant retired and cost of removal, less salvage, are charged to accumulated depreciation.

The cost of maintenance and repairs is charged to the appropriate operating expense and clearing accounts. The cost of renewals and betterments is charged to the appropriate utility plant account, except the cost of minor replacements which is charged to maintenance expense.

The present value of estimated decommissioning costs of $134,624,000 for nuclear units in service (assuming mothballing) is being charged to customers subject to the jurisdictions of the Virginia and West Virginia Commissions. For the remaining jurisdictions, estimated decommissioning costs are being recorded on a straight-line method based upon estimated service lives.

Nuclear Fuel:
Progress payments are being made for fuel to be owned or leased.

Amortization of owned nuclear fuel is provided on a unit of production basis sufficient to amortize the cost over the estimated service life.

The Company is collecting estimated future storage and disposal costs for spent fuel as authorized by the regulatory commissions in each jurisdiction. Such costs for Virginia and West Virginia jurisdictional customers are collected through fuel adjustment clause procedures while costs for North Carolina and Federal Energy Regulatory Commission (FERC) jurisdictional customers are collected through base rates.

Operating expenses include reprocessing costs for Virginia jurisdictional customers, permanent storage costs for North Carolina and West Virginia jurisdictional customers and projection of interim storage costs only for FERC jurisdictional customers.

Subsidiaries:
The Company has two wholly-owned subsidiaries. Laurel Run Mining Company is engaged in the underground mining of coal, which is utilized solely by the Company. Virginia Nuclear, Inc. was organized to explore for uranium reserves; however, no such activities are presently being conducted.

Federal Income Taxes:
The Company's practice is to reduce the current provision for Federal income taxes to reflect the tax benefit resulting from the use of the double-declining-balance method of depreciation for property additions, the adoption of the Asset Depreciation Range and Class Life Systems, and the adoption of the Accelerated Cost Recovery System. Effective with property additions placed in service in 1974, the Company has provided deferred income taxes on the aforementioned benefit and, subsequently, has provided deferred taxes on other differences between book income and income taxable for Federal income taxes to the extent permitted by the regulatory commissions having jurisdiction.

Investment Tax Credits:
Accumulated investment tax credits are being amortized over the service lives of the property giving rise to such credits.

An additional investment tax credit of 1% related to the Tax Reduction Act Stock Ownership Plan (TRASOP) does not affect net income and is recorded as a liability until the contribution is made to the TRASOP trust.

Allowance for Funds Used During Construction:
The applicable regulatory Uniform Systems of Accounts defines AFC as the net cost of borrowed funds used for construction purposes and a reasonable rate on other funds when so used.

The Company separately determines rates and reports amounts applicable to borrowed funds, calculated on a net of tax basis, and to equity funds. In accordance therewith, for 1982, 1981 and 1980, aggregate rates of 8.39%, 8.06% and 7.79%, respectively, were employed for the accrual of AFC.

For expenditures on the Bath County Pumped Storage Project after December 31, 1979, AFC is being accrued in an amount equal to the net of tax cost of borrowings associated with the project financing.

In August 1981, the Virginia Commission approved the Company's proposal to eliminate AFC on additional construction expenditures for North Anna Unit 3 (see Note C for additional information) and on all new projects commencing after September 1, 1981, and granted rate relief to cover such elimination.

Deferred Fuel Costs:
The Company is deferring for accounting and rate-making purposes that portion of the cost of fuel consumed which, through the application of the annual fuel factor, may result in increased operating revenues in a later period. In the event that future developments dictate a change in the fuel adjustment billing lag period or in the fuel cost base, the Company will request regulatory approval to recover through billings to customers any unrecovered deferred fuel costs.

Deferred Interest:
The Company charges to operations an interest cost associated with variable interest rate loans based on the interest rate ceiling stated in the loan agreements. Amounts paid in excess of the amounts charged to operations are deferred pending refund from the applicable lending institutions.

Retirement Annuity Plan:
The Company has a contributory defined benefit retirement annuity plan and funds pension costs accrued. Prior service cost from changes in actuarial assumptions in 1981 is being provided in the accounts and funded on the basis of future salaries of participants currently covered by the plan.

Leases:
The Company's practice is to account for all leases as operating leases in accordance with the rate-making practices presently in effect.

B. Federal Income Taxes:

Details of Federal income taxes were as follows:

	Years		
	1982	1981 (Thousands)	1980
Computed tax expense at statutory rate on book income before Federal income taxes	**$205,291**	$155,966	$143,600
Increases (decreases) resulting from:			
Excess of tax over book depreciation not normalized	**(4,221)**	(14,354)	(12,982)
AFC	**(38,352)**	(39,011)	(51,868)
Investment tax credits, amortization	**(9,075)**	(8,843)*	(5,171)
Other, net	**14,051**	7,518*	(3,025)
	(37,597)	(54,690)	(73,046)
Total Federal income tax expense	**$167,694**	$101,276	$ 70,554
Current	**$ (8,463)**	$ 14,732	$ 11,200
Tax effects of timing differences:			
Liberalized depreciation	**51,036**	53,847	41,108
Abandoned project costs	**125,328**	9,870	38,582
Fuel related items:			
Current year deferred fuel adjustment	**10,846**	19,149	(19,087)
Reprocessing/disposal costs on nuclear fuel	**(14,009)**	(13,063)	(7,988)
Fuel expense—nuclear plant testing	**(5,280)**	(2,410)	(3,663)
Nuclear fuel—owned	**(4,946)**	5,572	(2,669)
Virginia gross receipts taxes	**(1,902)**	(1,429)	(2,460)
Nuclear decommissioning costs	**(743)**	(994)	(764)
Spare parts inventory adjustment	**(1,004)**	(3,117)	4,120
Accelerated amortization	**(1,496)**	(1,547)	(1,547)
Indirect construction costs	**3,811**	2,310	2,800
Cost of removal of property retirements	**6,622**	2,057	3,729
Customer accounts reserve	**242**	(812)	
Deferred interest	**1,872**	2,293	
Other	**1,114**	500	16
	171,491	72,226	52,177
Investment tax credits:			
Gross	**(1,035)**	15,554	11,798
Amortization	**(9,075)**	(8,843)*	(5,171)
Net deferred investment tax credits	**(10,110)**	6,711	6,627
Federal income tax expense—operating income	**152,918**	93,669	70,004
—non-operating income	**14,776**	7,607	550
Total Federal income tax expense	**$167,694**	$101,276	$ 70,554

*See Note O to Financial Statements for the effects on the 1981 provision for Federal income taxes of a rate refund and a change in amortization of investment tax credits applicable to nuclear fuel.

The Company has investment tax credit carry-forwards of $198,300,000, of which $25,857,000, $18,554,000, $63,360,000, $49,862,000 and $40,667,000 will expire, unless used, in 1993, 1994, 1995, 1996 and 1997, respectively.

C. Abandoned Project Costs:

Due to sharply increased estimates of construction costs for the completion of North Anna Unit 3 and the availability of adequate replacement power at a cost well below the estimated cost of generation from this Unit, on November 19, 1982, the Company canceled plans for construction of this Unit. At December 31, 1982, the costs related to the Unit which have been deferred on the balance sheet were $456.0 million. In addition, $68.5 million of certain materials and supplies (and related AFC) has been designated for use in the operation or construction of other generating units, and $46.0 million of property and equipment has been transferred to other generating facilities either in service or under construction. In addition, the loss of certain income tax benefits that would have been available to the Company in 1982 if the Unit had not been canceled totaled $13.3 million, which amount has also been deferred. The Company will request rate relief to recover the amount deferred ($469.3 million) and any subsequent cancellation costs, but cannot give any assurance as to the regulatory treatment to be granted.

In November 1980, the Company canceled the construction of North Anna Unit 4. Investment in the Unit at December 31, 1982, amounted to $131.6 million, net of transfers of certain parts and equipment to other projects. After considering additional costs which may be incurred, the loss is presently estimated to be $154.5 million. In March 1977, the Company canceled the construction of Surry Units 3 and 4, for which $98.4 million was expended at December 31, 1982. These abandoned project costs incurred are being collected in rates and are being amortized over a ten-year period for accounting and rate-making purposes.

D. Supplementary Income Statement Information:

The amounts of royalties and advertising costs were not significant. Taxes other than Federal income taxes charged to expenses were as follows:

	Years		
	1982	1981	1980
		(Thousands)	
Taxes, other than Federal income taxes:			
Real estate and property	**$ 36,107**	$ 33,577	$ 29,182
State and local gross receipts	**73,737**	65,750	71,838
Other	**24,969**	21,584	16,436
Total	**$134,813**	$120,911	$117,456

E. Leases:

Rents charged to expenses consisted of the following:

	Years		
	1982	1981	1980
		(Thousands)	
Operating leases:			
Nuclear fuel	**$61,625**	$38,989	$21,140
Combustion turbines	**5,351**	5,451	5,524
Other (principally buildings and data processing equipment)	**14,075**	10,771	11,206
Total	**$81,051**	$55,211	$37,870

In 1971, the Company sold and leased back 28 combustion turbines for a term of 20 years (plus two optional five-year renewal terms). Annual rental payments are $6,444,000 during the second ten-year term. Additional rentals were accrued during the first ten years when payments represented only interest, so that the annual effect on net income would be equalized over the twenty-year period. Deferred credits-other, at December 31, 1982 and 1981, include $18,448,000 and $19,828,000, respectively, with regard to such accruals. Had the lease been capitalized, the net asset value and present value of the lease commitment would be $18,461,000 and $39,772,000, respectively, at December 31, 1982, and $20,591,000 and $42,601,000, respectively, at December 31, 1981.

The Company has heat supply contracts for the nuclear fuel for Surry Units 1 and 2 providing for an aggregate commitment of $110 million at December 31, 1982. Quarterly payments are charged to income in amounts sufficient to pay for the fuel burned during each quarter (excluding reprocessing and permanent disposal costs) plus interest. Had the contracts been capitalized, the net asset value and present value of these commitments would be $104,122,000 and $106,233,000, respectively, at December 31, 1982, and $98,930,000 and $101,822,000, respectively, at December 31, 1981.

In 1974, the Company sold and leased back three office buildings for terms of twenty years (plus two optional five-year renewal terms). Annual rental payments are $730,000 during the initial terms of the leases. In 1978, the Company leased a newly constructed headquarters office building for a term of thirty years (plus four optional five-year renewal terms). Annual rental payments are $2,993,000 during the initial term of the lease. Had the leases been capitalized, the net asset value and present value of the lease commitments would be $34,042,000 and $38,825,000, respectively, at December 31, 1982, and $35,565,000 and $39,490,000, respectively, at December 31, 1981.

If the Company had capitalized the above noted leases and contracts, the increase in operating expenses would not have been material.

The Company is responsible for expenses in connection with the leased turbines, nuclear fuel and buildings noted above, including insurance, taxes and maintenance.

F. Depreciation:

The provision for depreciation based on mean depreciable plant was as follows:

	Electric	Gas	Common
1982	3.3%	3.1%	5.1%
1981	3.3	3.1	4.1
1980	3.3	3.1	4.0

G. Jointly Owned Plant Under Construction:

On April 27, 1982, the Company received approximately $194 million from Allegheny Power System, Inc. (APS) as initial payment for the sale of an approximate 20% undivided interest in the Bath County Pumped Storage Project with a resulting increase in balance available for common stock of $3.9 million and earnings per share of $.035. Under the agreements, APS is committed to increase its participation to 40% through either further purchases of undivided interests in the project or a capacity purchase agreement. Also APS will be entitled to increase its 40% participation to 50% before December 31, 1984.

The agreements provide for APS to continue to pay approximately 20% of ongoing construction costs through part of 1984 (based on the present construction schedule). If the total project costs exceed the present estimate, APS would not be obligated to pay for any portion of the excess, but if APS does not pay its proportionate share of any such excess costs, its ownership interest would be correspondingly reduced. The Company would receive additional cash reimbursements for future expenditures, a reduction in its capital requirements or a combination of both, in the amount of about $96.7 million for APS's acquisition of this approximately 20% ownership interest. In addition, if APS elects to increase its ownership interest to 40%, the Company's share of the project costs would be reduced by about an additional $300 million.

The Company's share of investment in the project at December 31, 1982, was $786.8 million.

The Company is responsible for its own financing for construction costs and for the operation of the project. When the project becomes operational, APS will pay a proportionate share of the expenses incurred on an ongoing basis.

H. Preferred Stock Subject to Mandatory Redemption:

Preferred Stock Subject to Mandatory Redemption, $100 par, at December 31, 1982, was represented by the following:

Dividend	Authorized and Outstanding Shares	Entitled Per Share Upon Voluntary Liquidation Redemption: Amount	Through	And Thereafter To Amounts Declining In Steps To
$7.325	700,000	$110.00	3/31/83	$101.00 after 3/31/88
8.40	800,000	115.00	3/31/84	100.00 after 3/31/04
9.125	184,000	107.00	9/19/86	102.00 after 9/19/91
8.20	600,000	115.00	9/20/87	100.41 after 9/20/96
8.60	335,270	107.00	12/19/87	100.00 after 12/19/97
8.625	370,000	108.63	6/20/83	100.00 after 6/20/02
8.925	280,000	108.93	9/20/84	100.00 after 9/20/09
	3,269,270			
Less shares due within one year.......	49,834			
Total	3,219,436			

Sinking fund requirements call for annual redemption at $100 per share as follows:

Dividend	Shares	Beginning	Ending	Dividend	Shares	Beginning	Ending
$8.60	11,834	Dec. 1978	Dec. 2010	$8.625	18,500	June 1984	June 2002
9.125	8,000	Sept. 1981	Sept. 2000	8.925	10,500	Sept. 1984	Sept. 2009
8.20	30,000	Sept. 1983	Sept. 1996	8.40	32,000	April 1985	April 2009
7.325	28,000	April 1984	April 2008				

Maturities through 1987 are as follows: 1983-$4,983,000; 1984-$10,683,000; and 1985 through 1987-$13,883,000.

The total number of authorized shares for all preferred stock is 7,500,000 shares. Upon involuntary liquidation, all preferred stock shares are entitled to receive $100 per share plus accrued dividends. Dividends are cumulative and payable March 20, June 20, September 20 and December 20.

I. Preferred and Preference Stock Not Subject to Mandatory Redemption and Common Stock:

Preferred Stock Not Subject to Mandatory Redemption:

Preferred Stock Not Subject to Mandatory Redemption, $100 par, at December 31, 1982, was represented by the following:

Dividend	Authorized and Outstanding Shares	Entitled Per Share Upon Voluntary Liquidation Redemption: Amount	Through	And Thereafter To Amounts Declining In Steps To
$5.00	106,677	$112.50		
4.04	12,926	102.27		
4.20	14,797	102.50		
4.12	32,534	103.73		
4.80	73,206	101.00		
7.72	350,000	103.50	5/31/84	$101.50 Thereafter
8.84	350,000	104.00	8/31/85	101.00 Thereafter
7.45	400,000	103.00	2/29/84	101.00 Thereafter
7.20	450,000	103.00	1/31/85	101.00 Thereafter
7.72(1972 Series)	500,000	103.00	9/30/85	101.00 Thereafter
9.75	600,000	106.50	2/28/86	101.00 after 2/28/91
Total	2,890,140			

Preference Stock Not Subject to Mandatory Redemption—30,000,000 Shares Authorized:

In 1975, the Company issued 2,400,000 shares of $2.90 Dividend Preference Stock, no par, at $23.90 per share which aggregated $57,360,000. The preference stock is redeemable at the Company's option at $26.93 per share prior to May 1, 1985, and thereafter declines in steps to $25.25 on May 1, 1990. Upon liquidation, all shares are entitled to receive $25 per share plus accrued dividends. Dividends are cumulative and payable March 20, June 20, September 20 and December 20.

Common Stock:

Common stock was represented by 119,517,688 shares outstanding at December 31, 1982. In addition, 2,380,476 shares (based on the conversion price of $21.00 per share) are reserved for conversion of the 3⅝% Convertible Debentures due May 1, 1986. During the years 1980 through 1982, the following changes in common stock occurred:

	Years					
	1982		1981		1980	
	Shares Outstanding	Amount	Shares Outstanding	Amount	Shares Outstanding	Amount
Balance at January 1	104,768,299	$1,457,072,496	99,954,157	$1,400,874,668	92,874,112	$1,319,303,162
Changes due to:						
Public Offering	10,500,000	132,442,500	2,000,000	22,290,000	5,000,000	53,950,000
Dividend Reinvestment Plan	2,604,301	34,164,513	1,575,354	18,386,675	1,505,423	16,378,806
Customer Installment Plan (*):						
1982-1983		3,114,490				
1981-1982	650,708	5,076,606		3,029,914		
1980-1981			544,163	3,670,898		2,473,746
Employee Savings Plan	802,431	10,572,256	694,181	7,974,574	574,622	6,261,638
Transfer from Other Paid-In Capital		835,772		835,772		2,507,316
Other	191,949	2,549,923	444	9,995		
Balance at December 31	119,517,688	$1,645,828,556	104,768,299	$1,457,072,496	99,954,157	$1,400,874,668

(*) Shares are issued at the end of the plan year, which extends from September 1 through August 31.
On April 21, 1982, the number of authorized shares was increased from 120,000,000 to 150,000,000 shares.

J. Loans Payable, Pending Permanent Financing:

		Year End		Daily Average Outstanding		
	Maturity	Amount	Interest Rate (1)	Amount	Interest Rate (1)	Maximum Outstanding
1982						
Commercial paper	(2)	$ 83,972,000	9.30%	$110,609,000	12.71%	$227,720,000
Master notes	(3)	10,611,000	8.70	13,224,000	10.48	23,446,000
Pollution control notes	(3)	8,750,000	6.74	6,734,000	8.20	8,750,000
1981						
Commercial paper	(2)	148,896,000	13.61	184,608,000	16.60	279,395,000
Master notes	(3)	9,542,000	12.75	2,965,000	14.26	18,237,000
Pollution control notes	(3)	6,500,000	9.55	5,781,000	8.81	9,660,000
1980						
Commercial paper	(2)	72,003,000	18.25	155,772,000	13.54	280,525,000
Master notes	(3)	2,058,000	15.00	3,520,000	10.47	12,300,000
Pollution control notes	(2)	9,660,000	7.26	5,177,000	7.09	9,660,000

(1) Weighted average interest. (2) Principally 30 to 90 days. (3) Maximum 180 days.

Available bank lines-of-credit amounted to $446,800,000 at December 31, 1982, including $200,000,000 applicable to revolving credit agreements effective through August 30, 1985. The Company maintains compensating balances of up to 10% or pays fees in lieu of balances in connection with its lines-of-credit. Utilization under the lines-of-credit may require additional balances or fees. Compensation for the revolving credit agreements are consistent with the requirements for the lines-of-credit.

K. Long-Term Debt:

Long-term debt outstanding at December 31, 1982:

First and refunding mortgage bonds(1):	
Series DD 10½%, due 1983	$ 75,000,000
Series K 3⅛%, due 1984	25,000,000
Series L 3¼%, due 1985	25,000,000
Series A 6⅞%, due 1985	8,000,000(a)
Series M 4⅛%, due 1986	20,000,000
Series N 4½%, due 1987	20,000,000
Series O 3⅞%, due 1988	25,000,000
1981 Series A 15¾%, due 1989	100,000,000
Series P 4⅝%, due 1990	25,000,000
Series Q 4⅞%, due 1991	30,000,000
Series R 4⅜%, due 1993	30,000,000
Series S 4½%, due 1993	29,985,000
Series FF 11%, due 1994	100,500,000
Series EE 11%, due 1994	71,948,000
Series T 4½%, due 1995	56,600,000
1981 Series B 15¾%, due 1996	8,000,000
1981 Series C 15¾%, due 1996	30,000,000
Series U 5⅛%, due 1997	49,290,000
Series V 6⅞%, due 1997	50,000,000
Series KK 8.95%, due 1998	55,000,000
Series W 7⅛%, due 1999	85,000,000
Series X 7¾%, due 1999	75,000,000
Series Y 9%, due 2000	83,725,000
1980 Series A 12½%, due 2000	75,000,000
Series Z 8⅞%, due 2000	83,725,000
Series AA 7⅜%, due 2001	90,000,000
Series BB 7½%, due 2001	50,000,000
Series CC 7⅜%, due 2002	100,000,000
Series E 8½%, due 2002	15,000,000(a)(b)
Series C 6.15%, due 2003	8,000,000(a)
1979 Series B 9.95%, due 2004	135,000,000
Series A 8½%, due 2005	18,000,000(a)
Series GG 10%, due 2005	100,000,000
Series HH 9¼%, due 2006	100,000,000
Series B 6¾%, due 2006	20,000,000(a)
Series II 8¾%, due 2006	100,000,000
Series JJ 8⅝%, due 2007	150,000,000
Series LL 9⅝%, due 2008	150,000,000
1979 Series A 10¼%, due 2009	99,961,000
1982 Series D 8¾%, due 2012	75,000,000(a)(b)
Total	2,447,734,000
Term notes ($66,000,000 issued in 1982)(2)	414,500,000
Convertible debentures 3⅝%, due 1986	49,990,000
Pollution control revenue bonds(3)	42,500,000
Bath County project financing(4)	250,000,000
	3,204,724,000
Less amounts due within one year:	
First and refunding mortgage bonds	75,000,000
Sinking fund obligations(1)	10,198,000
Term notes(2)	17,500,000
Pollution control revenue bonds(3)	2,250,000
Less unamortized discount—net of premium	10,735,000
Total long-term debt	$3,089,041,000

(a) Pollution Control Series. (b) Issued in 1982.

The Company redeemed $215,216,000 of long-term debt and sinking fund obligations due in 1982. Maturities (including cash sinking fund obligations) through 1987 are as follows: 1983—$104,948,000; 1984—$231,000,000; 1985—$452,750,000; 1986—$105,115,000; and 1987—$58,375,000.

(1) The Mortgage provides for sinking funds as follows:

	Commencing	Annual Sinking Fund Requirements
Series K through CC	*	$ 9,558,750
Series EE and FF	Begun	13,250,000
Series KK	1984	2,750,000
1979 Series A and B	1985	10,750,000
1980 Series A	1986	4,875,000
Pollution Control Series A	1986	500,000
1981 Series C	1987	3,000,000
Pollution Control Series C	1989	375,000
Pollution Control Series B	1992	250,000

* The Company may satisfy these requirements by waiving the privilege to issue an equal amount of Bonds by substituting property therefor and intends to do so in 1983.

Substantially all of the Company's property is subject to the lien of the Mortgage.

(2) Term Notes:

Principal Amount	Maturity	Variable Interest Rate: Percentage of Base Lending Rate of	Variable Interest Rate: Not to Exceed an Average of	Fixed Interest Rate
$ 5,000,000	1984	115%	9.9%	
5,000,000	1984	107½	9.9	
11,000,000	1984	65	11	
20,000,000	1985	115	8¾	
5,000,000	1985	65	11	
50,000,000	1988	(a)	9	
96,000,000				
10,000,000	1983			8¼%
2,500,000	1983			11⅜
5,000,000	1983			8⅝
6,000,000	1984			8.55
10,000,000	1984			8¼
50,000,000	1984			10¼
25,000,000	1984			11⅞
25,000,000	1984			9.95
25,000,000	1984			10.13
25,000,000	1984			10.21
5,000,000	1985			8⅝
15,000,000	1985			15¼
5,000,000	1985			15½
15,000,000	1985			11⅞
25,000,000	1985			10.21
50,000,000	1985			9.74
10,000,000	1987(b)			14½
10,000,000	1995			12⅜
318,500,000				
$414,500,000				

(a) 118% of the higher of commercial paper rate plus ½ of 1% or base lending rate. Interest not to be less than 8%.
(b) $2,500,000 mature annually beginning in 1984.

(3) Pollution Control Revenue Bonds:

Principal Amount	Maturity	Interest Rate	Mandatory Sinking Fund Requirements: Annual Amount	Mandatory Sinking Fund Requirements: Commencing
$ 2,000,000	1983	7.4%	None	
4,000,000	1989	8.0	$250,000	Begun
			500,000	1984
			750,000	1987
22,000,000	2002	5⅝	500,000	1990
14,500,000	2004	8¾	750,000	1990
$42,500,000				

(4) In 1980, the Company issued a collateral note securing borrowings of a trust which is financing construction expenditures (including interest) after 1979 on the Bath County Pumped Storage Project. Borrowings under the present arrangements, which increased by $850,000 during 1982, are limited to $250 million and mature on December 31, 1985. Weighted average interest for 1982, including fees for supporting lines-of-credit, amounted to 13.5%.

L. Effect of Rate Increases on Operating Revenues:

In 1982, the Company obtained rate relief of about $134.3 million on an annual basis from the three State Commissions, FERC and non-jurisdictional customers.

Rate increases and decreases, exclusive of fuel cost recovery, which became effective for portions of the following years increased (decreased) operating revenues for the respective years by the approximate amounts shown:

(Millions)	**1982**	1981	1980
Electric	**$71.3***	$92.2	$36.4
Gas		(.2)	(.7)

* Includes approximately $8.3 million subject to refund.

M. Retirement Annuity Plan:

The Company's Retirement Annuity Plan covers virtually all employees. Costs to the Company under the plan were: 1982—$13,541,000; 1981—$10,575,000; and 1980—$10,826,000. The present value of benefits, as determined by the actuaries, were as follows:

	January 1, 1982	January 1, 1981
Vested accumulated plan benefits	$142,170,000	$125,756,000
Nonvested accumulated plan benefits	19,407,000	16,373,000
Total	$161,577,000	$142,129,000
Plan net assets available for benefits	$174,581,000	$159,027,000

A 7% rate of return was used in determining the present value of vested and non-vested accumulated plan benefits for both years.

N. Commitments and Contingencies:

The Company has made substantial commitments in connection with its construction program, which is presently estimated to be $780 million for 1983. Additional financing is contemplated in connection with this program.

In order to assure additional sources of coal fired generation to displace its oil fired generation, the Company has committed to a contract providing for the purchase of capacity and energy from another utility in 1983 and 1984. Under the terms of the contract, the Company is committed to payments of approximately $62.1 million in 1983 and $62.7 million in 1984. The Company has an option under the contract to purchase additional energy at an estimated cost of $56.4 million in 1983 and $49.8 million in 1984. Total purchases under the contract will be at a cost below that of an equivalent amount of the Company's oil fired generation.

In 1979, settlement was reached in the Westinghouse uranium dispute which provides for cash and discounts on uranium and goods and services over the period 1979-1997 which are estimated to equal the value of contracts litigated had they been fully performed by Westinghouse. Through December 31, 1982, the Company had received $190.1 million in cash, goods and services, $14.1 million of which was received in 1982. Settlement proceeds are applied to reduce fuel expenses to the extent that fuel expenses reflect higher costs as a result of the breached contracts. In 1979, the Company filed with the Internal Revenue Service a request for a ruling that the value received from the settlement be treated as a reduction in fuel expense over the life of the nuclear fuel, and not as taxable income in the year of the settlement. The ruling, received in June 1981, held that cash and the value of discounts on purchases of equipment and services accrued at the time of settlement and could be used to offset the damages in the cost of replacement uranium acquired up to the date of settlement. This treatment was not extended to replacement uranium acquired after the date of settlement. If the Company is required to pay taxes as a result of the settlement, such provision would be normalized in order to match the tax effect of the settlement with the credit to fuel expenses per books.

A group of utilities, including the Company, has established Nuclear Electric Insurance Limited (NEIL), a mutual insurance company that provides insurance for replacement power costs resulting from an accident at a nuclear site. The Company has purchased the maximum coverage available, which is up to $2.5 million per week per unit for the first 52 weeks of coverage and up to $1.25 million per week per unit for the next 52 weeks, subject to an initial 26-week deductible period. In addition, NEIL began providing excess property damage insurance through a separate program that commenced on November 15, 1981, to provide at least $500 million of property insurance coverage to meet losses in excess of $500 million. The company has committed to purchase the maximum amount available. The annual premiums for the current policy year are $5.8 million for the replacement power insurance and $2.1 million for the excess property coverage. Each program also obligates participants to a retrospective premium adjustment for six years following each policy year. These adjustments are not to exceed 5 times the annual premium, in the case of the replacement power insurance, and 7.5 times the annual premium, in the case of the excess property coverage, in the event that losses exceed the accumulated funds of the applicable program.

For a discussion of the possible sale of a portion of the North Anna Station and related facilities see *Capital Resources* under MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

O. Quarterly Financial Data (Unaudited):

The following amounts (not examined by independent certified public accountants) reflect all adjustments, consisting of only normal recurring accruals, necessary in the opinion of the Company for a fair statement of the results for the interim periods, except as disclosed below for the adjustments recorded in the second quarter of 1982 and in the third and fourth quarters of 1981.

Quarter	Operating Revenues	Operating Income	Balance Available for Common Stock	Earnings Per Share of Common Stock	Quarter	Operating Revenues	Operating Income	Balance Available for Common Stock	Earnings Per Share of Common Stock
1982	(Thousands)				1981	(Thousands)			
1st	$612,744	$134,395	$60,783	$.56	1st	$554,203	$106,544	$40,260	$.40
2nd	536,874	102,012	32,665	.29(1)	2nd	484,984	97,194	23,491	.23
3rd	626,024	142,029	69,607	.62	3rd	567,628	141,427	63,992	.63(3,4)
4th	585,128	127,160	58,543	.51	4th	555,038	123,467	52,871	.51(2)

Results for interim periods may fluctuate as a result of weather conditions, rate relief and other factors.

(1) See Note G for additional information concerning the sale of a portion of the Bath County Pumped Storage Project and the resulting increase in balance available for common stock and earnings per share.

(2) In December 1981, eleven of the Company's North Carolina municipal customers terminated contracts for electric service by the Company to purchase their own generating capacity from another utility. Accordingly, the Company agreed to phase out its wholesale power contracts with these customers over a two-year period beginning December 30, 1981, in return for a payment to the Company on that date of approximately $15.5 million. Of this amount, $13.3 million was credited to other income with a resulting increase in balance available for common stock and earnings per share of $7.2 million and $.07, respectively, and $2.2 million was credited to accumulated amortization of nuclear fuel.

(3) From September 1978 through August 1981, the Company provided a reserve for the difference between interim rates in effect for FERC jurisdictional customers and estimated final rates. The Company neither sought nor received regulatory approval to provide deferred taxes on this reserve which was not considered to be deductible for Federal income tax purposes until a refund was made. As a result of a final rate order received in the third quarter of 1981, a refund substantially equal to the amount previously provided was made. The tax benefit of this refund had the effect of reducing the Company's 1981 provision for Federal income taxes by $12.4 million and of increasing 1981 earnings per share by $.12.

(4) Beginning in the third quarter of 1981 the investment tax credit applicable to nuclear fuel is being amortized over the average burn life of the fuel, which is three years, rather than over the average composite life of all plant assets. This refinement of the Company's method of amortizing the tax credits had the effect of reducing the 1981 provision for Federal income taxes by $5.3 million (including $3.3 million applicable to periods prior to 1981) and of increasing 1981 earnings per share by $.05. The effect of this refinement on the results of operations of periods prior to 1981 would not have been significant.

P. Supplementary Data On Changing Prices (Unaudited):

The following supplementary information is supplied in accordance with the requirements of FASB Statement No. 33, Financial Reporting and Changing Prices, for the purpose of providing certain information about the effects of changing prices. It should be viewed as an estimate of the approximate effect of inflation, rather than as a precise measure.

Constant dollar amounts represent historical costs stated in terms of dollars of equal purchasing power, as measured by the Consumer Price Index for All Urban Consumers (CPI-U). Current cost amounts reflect the changes in specific prices of plant from the date the plant was acquired to the present, and differ from constant dollar amounts to the extent that specific prices have increased more or less rapidly than prices in general.

The current cost of property, plant and equipment, which includes intangible plant, property held for future use and construction work in progress, represents the estimated cost of replacing existing plant assets and was determined by indexing the surviving plant by the Handy-Whitman Index of Public Utility Construction Costs. The current cost of land and general plant was determined by using the CPI-U. The current year's provision for depreciation on the constant dollar and current cost amounts of property, plant and equipment was determined by applying the Company's depreciation rates to the indexed plant amounts.

Fuel used in electric generation has been restated to reflect the constant dollars and current cost of nuclear fuel. The cost of other types of fuel used in electric generation and gas purchased for resale have not been restated since these costs are considered to be current.

Fuel inventories, with the exception of nuclear fuel, have not been restated from their historical cost in nominal dollars. The nuclear fuel inventory is considered an integral part of the plant investment and, therefore, should be restated and adjusted to net recoverable cost. As indicated above, other types of fuel inventories have not been restated since the costs of these assets are considered to be current.

Preferred stock subject to mandatory redemption has been classified as a monetary liability in determining the gain from decline in purchasing power of dollars related to net amounts owed, in accordance with the definition of a monetary liability in FASB Statement No. 33.

As prescribed in Statement 33, income taxes were not adjusted.

To properly reflect the economics of rate regulation in the Statement of Income from Continuing Operations, the adjustment of property, plant and equipment to net recoverable cost should be offset or combined, as appropriate, by the gain from the decline in purchasing power of the dollars related to net amounts owed. During a period of inflation, holders of monetary assets suffer a loss of general purchasing power while holders of monetary liabilities experience a gain. The gain from the decline in purchasing power of the dollars related to net amounts owed is primarily attributable to the substantial amount of debt which has been used to finance property, plant and equipment. Since the depreciation on this plant is limited by regulation to the recovery of historical costs, a holding gain on debt is not allowed and the Company is limited to recovery of the embedded cost of the asset.

Statement of Income from Continuing Operations Adjusted for Changing Prices (Unaudited)

	For The Year Ended December 31, 1982		
	Conventional Historical Cost	Constant Dollar Average 1982 Dollars	Current Cost Average 1982 Dollars
		(Thousands)	
Operating revenues	$2,360,770	$2,360,770	$2,360,770
Fuel used in electric generation	542,712	562,645	607,853
Depreciation	190,960	401,918	430,439
Other operating and maintenance expense	968,584	968,584	968,584
Federal income taxes	152,918	152,918	152,918
Interest expense (net of allowance for borrowed funds used during construction)	281,551	281,551	281,551
Other income and deductions-net	(54,544)	(54,544)	(54,544)
	2,082,181	2,313,072	2,386,801
Income (loss) from continuing operations (excluding adjustment to net recoverable cost)	$ 278,589	$ 47,698*	$ (26,031)
Increase in specific prices (current cost) of property, plant and equipment held during the year**			$ 331,330
Adjustment to net recoverable cost		$ (36,038)	209,298
Effect of increase in general price level			(502,937)
Excess of increase in general price level over increase in specific prices after adjustment to net recoverable cost			37,691
Gain from decline in purchasing power of dollars related to net amounts owed		168,320	168,320
Net		$ 132,282	$ 206,011

* Including the adjustment of property, plant and equipment to net recoverable cost, the income from continuing operations on a constant dollar basis would have been $11,660,000 for 1982.

** At December 31, 1982, current cost of property, plant and equipment, net of accumulated depreciation and amortization, was $11,048,342,000, while historical cost or net cost recoverable through depreciation and amortization was $5,791,044,000.

Five Year Comparison of Selected Supplementary Financial Data Adjusted for Effects of Changing Prices (Unaudited)

	Years Ended December 31,				
	1982	1981	1980	1979	1978
	(In Thousands* of Average 1982 Dollars)				
Operating revenues	$2,360,770	$2,295,977	$2,484,808	$2,266,639	$2,168,869
Historical cost information adjusted for general inflation					
Income (loss) from continuing operations (excluding adjustment to net recoverable cost)	$47,698	$13,793	$103,331	$107,785	
Income (loss) per common share (after dividend requirements on preferred and preference stock)	$(0.08)	$(0.46)	$0.37	$0.40	
Net assets at year-end at net recoverable cost	$2,491,154	$2,362,549	$2,475,904	$2,616,209	
Current cost information					
Income (loss) from continuing operations (excluding adjustment to net recoverable cost)	$(26,031)	$(41,695)	$57,868	$50,188	
Income (loss) per common share (after dividend requirements on preferred and preference stock)	$(0.74)	$(1.01)	$(0.10)	$(0.27)	
Excess of increase in general price level over increase in specific prices after adjustment to net recoverable cost	$(37,691)	$233,662	$509,449	$609,788	
Net assets at year-end at net recoverable cost	$2,491,154	$2,362,549	$2,475,904	$2,616,209	
General information					
Gain from decline in purchasing power of dollars related to net amounts owed	$168,320	$327,014	$455,949	$494,183	
Cash dividends declared per common share	$1.53	$1.51	$1.65	$1.84	$1.92
Market price per common share at year-end	$14.13	$12.08	$11.63	$13.21	$19.97
Average consumer price index (1967 = 100)	289.3	272.4	246.8	217.4	195.4

* Except per share amounts and indexes.

Ten Year Comparative Summary of Performance

		(Thousands)		
	1982	1981	1980	1979
Operating revenues:				
Electric	**$2,254,526**	$2,069,764	$2,049,518	$1,64[illegible]
Gas	**106,244**	92,089	70,256	5[illegible]
Total operating revenues	**2,360,770**	2,161,853	2,119,774	1,703,3[illegible]
Expenses (operation and maintenance)	**1,355,262**	1,292,318	1,390,817	1,069,2[illegible]
Depreciation	**190,960**	174,120	145,032	136,2[illegible]
Amortization of abandoned project costs	**21,221**	12,203	6,933	7,292
Taxes:				
Federal income:				
Currently payable (refundable)	**(8,463)**	14,732	11,200	8,449
Investment tax credits, including carry-back	**(1,035)**	15,554	11,798	570
Investment tax credits, amortization	**(9,075)**	(8,843)	(5,171)	(5,8[illegible])
Deferred—accelerated amortization	**(1,496)**	(1,547)	(1,547)	(1,5[illegible])
—liberalized depreciation	**51,036**	53,847	41,108	32,4[illegible]
—other	**121,951**	19,926	12,616	35,67[illegible]
Other	**134,813**	120,911	117,456	104,3[illegible]
Total operating expenses	**1,855,174**	1,693,221	1,730,242	1,386,9[illegible]
Operating income	**505,596**	468,632	389,532	316,3[illegible]
Other income:				
Allowance for other funds used during construction	**43,863**	44,264	73,206	66,603
Allowance for funds used during construction				
Miscellaneous, net	**10,681**	8,629	2,423	974
Total other income	**54,544**	52,893	75,629	67,577
Income before interest charges	**560,140**	521,525	465,161	383,971
Interest charges:				
Interest on long-term debt	**296,225**	280,012	234,561	204,392
Other	**24,836**	44,276	28,530	12,417
Allowance for borrowed funds used during construction	**(39,510)**	(40,543)	(39,550)	(29,305)
Total interest charges	**281,551**	283,745	223,541	187,504
Income before cumulative effect of change in accounting method	**278,589**	237,780	241,620	19[illegible]
Cumulative effect to January 1, 1974 of accruing estimated unbilled revenues, net of taxes				
Net income	**278,589**	237,780	241,620	196,467
Dividends paid:				
On preferred and preference stock	**56,995**	57,170	57,290	55,046
On common stock	**172,791**	144,937	133,005	120,638
Total dividends	**229,786**	202,107	190,295	175,684
Earnings reinvested in business	**$ 48,803**	$ 35,673	$ 51,325	$ 20,783
Shares of common stock—average (thousands)	**112,062**	101,856	95,520	86,965
Earnings per share of common stock	**$1.98**	$1.77	$1.93	$1.63
Dividends paid per share of common stock	**$1.52½**	$1.42½	$1.40	$1.38
Pay-out ratio	**77%**	80%	72%	85%
Return of capital:				
Common stock dividends	**88.47%**	40.22%	100.000%	(2)
Preferred stock dividends			3.300%	
Preference stock dividends			100.000%	
Utility plant at original cost	**$7,484,390**	$7,487,634	$6,836,094	$6,307,644
Utility plant expenditures	**$ 704,355**	$ 676,295	$ 681,120	$ 708,756
Accumulated depreciation and amortization	**$1,693,346**	$1,474,746	$1,249,629	$1,079,142
Capitalization:				
Preferred and preference stock	**$ 673,301**	$ 675,284	$ 677,268	$ 678,451
Common equity	**2,188,696**	1,952,476	1,861,656	1,731,762
Debt (excluding short-term debt)	**3,204,724**	3,263,090	3,019,053	2,681,360
Total capitalization	**$6,066,721**	$5,890,850	$5,557,977	$5,091,573
Short-term debt—pending permanent financing	**$ 103,333**	$ 164,938	$ 83,721	$ 131,730
Capitalization ratios:				
Preferred and preference stock	**11%**	12%	12%	13%
Common equity	**36**	33	34	[illegible]
Debt (excluding short-term debt)	**53**	55	54	[illegible]

(1) Includes non-recurring cumulative effect of change in accounting for unbilled revenues of $.24 per share.
(2) 1979 Return of capital was 33.02% for the first quarter and 91.95% for the remainder of the year.

1978	1977	1976	1975	1974	1973	1972
3,866	$1,313,937	$1,060,663	$ 998,933	$ 735,962	$ 524,963	$ 445,668
51,039	44,923	43,413	34,403	28,050	26,000	25,185
1,464,905	1,358,860	1,104,076	1,033,336	764,012	550,963	470,853
869,232	850,823	647,965	629,162	478,716	278,750	264,906
117,481	98,527	95,191	89,805	77,757	68,436	53,058
6,760	3,173					
23,163	9,191	2,209	(1,142)	(7,678)	(1,010)	(6,850)
40,294	23,548	35,568	2,286	(3,195)	3,901	7,368
(5,467)	(4,539)	(3,028)	(2,452)	(2,412)	(2,413)	(2,225)
(1,547)	(1,547)	(1,547)	(1,547)	(1,547)	(1,547)	(1,547)
38,509	13,101	12,320	9,360	3,202		
(22,294)	19,982	3,229	20,873	5,018	7,265	1,356
93,499	81,174	71,413	57,169	48,216	42,170	36,629
1,159,630	1,093,433	863,320	803,514	598,077	395,552	352,695
305,275	265,427	240,756	229,822	165,935	155,411	118,158
64,002	72,361					
		80,429	66,873	65,735	57,359	58,451
1,342	(663)	491	544	411	336	(156)
65,344	71,698	80,920	67,417	66,146	57,695	58,295
370,619	337,125	321,676	297,239	232,081	213,106	176,453
184,947	168,885	147,481	122,951	94,058	78,350	67,554
6,677	5,748	7,409	19,556	23,214	10,684	5,162
(24,869)	(27,301)					
166,755	147,332	154,890	142,507	117,272	89,034	72,716
3,864	189,793	166,786	154,732	114,809	124,072	103,737
				12,353		
203,864	189,793	166,786	154,732	127,162	124,072	103,737
53,588	47,719	43,821	35,971	30,419	24,147	16,472
103,474	91,225	82,923	70,786	60,165	54,796	46,905
157,062	138,944	126,744	106,757	90,584	78,943	63,377
$ 46,802	$ 50,849	$ 40,042	$ 47,975	$ 36,578	$ 45,129	$ 40,360
80,060	74,025	68,137	60,854	52,100	47,021	41,883
$1.88	$1.92	$1.80	$1.95	$1.86(1)	$2.13	$2.08
$1.30	$1.24	$1.22½	$1.18	$1.18	$1.16½	$1.12
69%	64%	67%	60%	71%	55%	54%
	72.654%	25.267%		100.000%	49.407%	100.000%
				100.000%		55.565%
$5,626,671	$5,109,099	$4,609,416	$4,142,900	$3,739,395	$3,298,447	$2,847,614
$ 529,186	$ 569,068	$ 481,601	$ 432,139	$ 460,912	$ 486,709	$ 472,819
$ 940,958	$ 803,604	$ 700,254	$ 609,304	$ 545,296	$ 476,121	$ 414,941
$ 651,634	$ 619,109	$ 583,807	$ 503,807	$ 446,447	$ 366,447	$ 296,447
1,627,179	1,493,521	1,334,639	1,211,282	1,042,677	948,369	810,121
2,460,060	2,238,400	2,038,150	1,803,150	1,578,350	1,289,890	1,242,440
$4,738,873	$4,351,030	$3,956,596	$3,518,239	$3,067,474	$2,604,706	$2,349,008
$ 3,437	$ 53,050	$ 26,500	$ 110,050	$ 256,945	$ 220,150	$ 88,400
14%	14%	15%	14%	15%	14%	13%
34	34	34	35	34	36	34
52	52	51	51	51	50	53

Ten Year Electric Operating Statistics

	1982	1981	1980	19[illegible]
Operating revenues (thousands):				
Residential	**$ 886,175**	$ 814,152	$ 806,156	$ 637,[illegible]9
Commercial	**592,118**	541,264	534,241	431,[illegible]1
Industrial	**309,632**	261,825	281,316	220,814
Other sales of electric energy	**447,149**	436,663	413,022	347,276
Other electric revenues	**19,452**	15,860	14,783	11,128
Total operating revenues—electric	**$2,254,526**	$2,069,764	$2,049,518	$1,647,928
Population served at retail—estimated	**3,682,000**	3,638,000	3,579,000	3,523,[illegible]0
Number of customers:				
Residential	**1,259,841**	1,238,530	1,208,500	1,174,3[illegible]1
Commercial	**126,237**	123,939	120,869	117,[illegible]5
Industrial	**943**	920	920	920
Other	**18,453**	17,749	16,878	15,8[illegible]3
Total customers	**1,405,474**	1,381,138	1,347,167	1,309,109
Sales of electricity—Mwh (thousands):				
Residential	**13,272**	13,399	13,154	12,397
Commercial	**9,886**	9,816	9,597	9,161
Industrial	**6,977**	6,416	6,459	6,460
Other	**9,845**	10,275	10,035	9,557
Total sales of electricity	**39,980**	39,906	39,245	37,575
Losses and miscellaneous system uses	**2,874**	2,983	3,244	2,909
Total distribution—energy supply	**42,854**	42,889	42,489	40,484
Source of electricity—Mwh (thousands):				
Steam—Fossil	**17,763**	16,539	18,840	2[illegible]1
—Nuclear	**17,421**	17,818	11,466	[illegible]5
Hydro	**679**	263	616	1,122
Other	**41**	201	208	356
Net purchased and interchanged	**6,950**	8,068	11,359	7,650
System output	**42,854**	42,889	42,489	40,484
Interchange deliveries for account of others	**326**	325	326	325
Company's service area output	**43,180**	43,214	42,815	40,809
Company's service area peak load—Mw	**8,879**	8,638	8,484	7,929
Power supply available for peak load—Mw				
Generating capability:				
Steam—Fossil	**6,104**	6,112	6,144	6,321
—Nuclear	**3,309**	3,199	2,329	2,448
Hydro	**326**	326	326	326
Other	**550**	439	439	439
Total generating capability	**10,289**	10,076	9,238	9,534
SEPA power disposed of in Company's service area	**165**	165	165	165
Available for firm peak load	**10,454**	10,241	9,403	9,699
Purchase (sale) outside service area	**300**	900	1,300	300
Available for service area peak load	**10,754**	11,141	10,703	9,999
BTU per kilowatt-hour generated	**10,829**	11,170	11,235	11,067
Average fuel cost per KWH generated-mills	**15.03**	17.77	21.76	20.44
Electric line—pole miles	**42,603**	42,502	42,297	42,149
Underground construction—miles of route	**11,207**	10,775	10,127	9,314

* Excludes the cumulative effect to January 1, 1974 of accruing estimated unbilled revenues shown as a nonrecurring item on the income staten[illegible]et of taxes.

.978	1977	1976	1975	1974	1973	1972
$ 563,561	$ 524,336	$ 420,150	$ 402,889	$ 308,834	$ 229,860	$ 191,924
392,101	365,340	298,681	288,357	211,486	150,758	130,599
182,901	176,573	144,770	137,181	106,309	66,131	58,785
268,213	242,686	193,096	166,854	106,018	75,170	61,440
7,090	5,002	3,966	3,652	3,315	3,044	2,920
$1,413,866	$1,313,937	$1,060,663	$ 998,933	$ 735,962*	$ 524,963	$ 445,668
3,465,000	3,415,000	3,365,000	3,315,000	3,270,000	3,225,000	3,185,000
1,138,470	1,100,876	1,071,528	1,041,234	1,018,346	989,471	954,374
115,121	111,662	108,197	105,942	105,531	103,253	100,175
920	920	920	918	916	910	894
15,446	14,922	14,462	14,881	13,045	12,350	11,817
1,269,957	1,228,380	1,195,107	1,162,975	1,137,838	1,105,984	1,067,260
12,405	11,867	11,137	10,373	9,850	9,911	8,775
9,170	8,762	8,455	7,970	7,307	7,330	6,471
6,152	6,022	6,011	5,404	5,658	5,535	5,136
9,340	8,806	8,510	7,741	7,120	7,268	6,529
37,067	35,457	34,113	31,488	29,935	30,044	26,911
2,901	2,792	2,261	2,585	2,518	2,335	2,199
39,968	38,249	36,374	34,073	32,453	32,379	29,110
`4,438	26,403	27,090	23,562	22,819	22,311	23,710
.4,098	9,481	7,740	8,969	5,953	6,857	370
967	444	599	988	774	949	1,071
399	625	407	226	629	459	558
66	1,296	538	328	2,278	1,803	3,401
39,968	38,249	36,374	34,073	32,453	32,379	29,110
325	325	326	325	325	315	312
40,293	38,574	36,700	34,398	32,778	32,694	29,422
7,805	7,902	7,040	7,133	6,734	6,900	6,232
6,321	6,321	6,321	6,321	5,684	4,866	4,306
2,448	1,550	1,576	1,576	1,576	1,576	788
326	326	326	326	326	326	326
439	439	454	469	530	530	530
9,534	8,636	8,677	8,692	8,116	7,298	5,950
165	165	165	165	165	165	132
9,699	8,801	8,842	8,857	8,281	7,463	6,082
300	300	313	316	251	122	680
9,999	9,101	9,155	9,173	8,532	7,585	6,762
11,018	10,933	10,739	10,892	10,868	10,673	10,529
14.04	15.23	12.94	13.06	12.43	4.98	4.63
41,698	41,446	41,186	40,663	40,121	39,578	39,055
8,395	7,794	6,824	6,266	5,641	4,772	4,055

Directors

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President, Virginia National Bankshares, Inc., Norfolk, VA

William W. Berry
President

James F. Betts
President, Continental Financial Services Company, Richmond, VA

Milton L. Drewer, Jr.
President, First American Bank of Virginia, McLean, VA

Mrs. Mary C. Fray
Culpeper, VA

Bruce C. Gottwald
President, Ethyl Corporation, Richmond, VA

Dr. Allix B. James
President Emeritus, Virginia Union University, Richmond, VA

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Chairman of the Board of Directors

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President, The Ahoskie Fertilizer Company, Inc., Ahoskie, NC

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President, VVKR Incorporated, Alexandria, VA

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Mrs. Mary C. Fray
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Chairman of the Board, Age 57

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Executive Vice President and Chief Operating Officer, Age 51

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Power Station Engineering and Construction, Age 57

John I. Oatts
Power Operations, Age 53

William L. Proffitt
Commercial Operations, Age 53

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B. D. Johnson
Vice President and Controller, Age 50

O. James Peterson, III
Vice President and Treasurer, Age 47

Tyndall L. Baucom, Age 41
Wadsworth Bugg, Jr., Age 61
Paul G. Edwards, Age 44
Gerald C. Headley, Jr., Age 48
Robert F. Hill, Age 46
Charles M. Jarvis, Age 54
Ronald H. Leasburg, Age 49
James T. Rhodes, Age 41
William C. Spencer, Age 50
William L. Stewart, Age 39
William N. Thomas, Age 59

Corporate Secretary

Linwood R. Robertson, Age 43

Division Vice Presidents

William H. Blackwell, Jr.
Eastern Division, Age 53

Richard W. Carroll
Western Division, Age 64

Eugene C. Keeling
Virginia Natural Gas, Age 59

Horace A. Keever, Jr.
Northern Division, Age 51

Randolph D. McIver
Southern Division, Age 52

David W. Poole
Central Division, Age 58

Stock and Convertible Debenture Listings

New York Stock Exchange Symbol—VEL
Newspaper Listing—VaEPw

Transfer Agents—Registrars

United Virginia Bank, Richmond
The Chase Manhattan Bank, N.A., New York

Annual Meeting

April 20, 1983

Cassette Recordings of this 1982 Annual Report are available as a service to the visually impaired. Requests should be directed to the Corporate Secretary of the Company.

Stockholder Information

If you have questions concerning your dividend payments, dividend reinvestment plan, change of address, consolidation of accounts, stock certificates, transfer of ownership or other related stockholder matters, please write or telephone our Stockholder Relations Department:
Stockholder Relations
Virginia Electric and Power Company
P.O. Box 26666
Richmond, Virginia 23261
(804) 771-3247

The photo of the discharge ring on page 11 was photographed by Vepco employee Ms. Barbara L. Stinnett.

Vepco
Virginia Electric and Power Company
P.O. Box 26666 • Richmond, Virginia 23261

1981 WL 723587 (W.Va.P.S.C.)

VIRGINIA ELECTRIC AND POWER COMPANY, a corporation. In the matter of increased rates and charges.

Case No. 80-290-E-42T

West Virginia Public Service Commission

May 29, 1981

FINAL ORDER

<<Signature>>Commissioner Otis D. Casto<<Signature>>Commissioner Elwin Bresette<<Signature>>Chairman E. Dandridge McDonald

At a session of the PUBLIC SERVICE COMMISION OF WEST VIRGINIA, at the Capitol in the City of Charleston on the 29th day of May, 1981.

PROCEDURE

On the 18th day of July, 1980, Virginia Electric and Power Company,a corporation, ("VEPCO" or "Company") filed its tariff designated P.S.C W.Va. No. 9, canceling P.S.C. W.Va. No. 8 , reflecting increased rates and charges of approximately $3,051,000 or 25 percent for furnishing electric service to approximately 21, 341 customers in the State of West Virginia, to become effective September 3 1980.

By order entered on August 29, 1980, VEPCO was made respondent herein, and the aforesaid revised tariff designated P.S.C W.Va.No. 9 was suspended and the use of the rates and charges stated therein defer-red until January 1, 1981. Said order also set for interim hearing the matters of rate of return, normalization of the federal income tax benefits resulting from the use of accelerated depreciation methods and the tax rate to be applied in the calculation of federal income taxes, to be held beginning October 20, 1980, in the Commission's hearing room at the Capitol in the City of Charleston. The hearing was held as scheduled and the Commission entered an order deciding the interim issues on the 29th day of December, 1980. The interim order granted VEPCO the opportunity to earn a 10.41 percent rate of return on its average jurisdictional rate base and deferred the Commission decision on the issue of normalization until the final hearing of this case. Interim rates were developed using a flow through method of accounting and thus do not include an amount reflecting VEPCO's proposal regarding normalization. The Commission's interim decision found VEPCO's cost of service allocated to its West Virginia jurisdictional business to be $9,611,000, that its going level revenues were at the $7,212,000 level and that a $2,399,000 deficiency in revenues existed. For the purposes of its interim order the Commission followed the proposed rate structure contained within the Company's July 18, 1980 filing, appropriately scaled downward, in order to achieve the revenue requirements as determined therein.

On the 21st day of January, 1981, the Commission entered an order setting this case for final hearing on the audited final issues for March 9, 1981 and each successive weekday thereafter until concluded in the commission's hearing room at the Capitol in the City of Charleston. The hearing was held as scheduled and the respondent submitted proof of the giving of notice in substantial compliance with the Commission's order of January 21, 1981.

Appearing at the hearing on behalf of the respondent were Michael A. Albert and Guy T. Tripp III, attorneys at law. Appearing on behalf of the Commission Staff were Robert W. Geake and Joseph A. Mancuso attorneys at law. Six witnesses appeared on behalf of the respondent and two witnesses testified for the Commission Staff. The Company presented one rebuttal witness. No protectants or intervenors appeared of record. As of the date of the hearing the Commission had received approximately 1,700 letters of protest from citizens within the Company's service area regarding this matter. Subsequent to the hearing the Commission has received approximately 180 letters of protest.

At the conclusion of the hearing held on March 9, 1981 this case was submitted for final decision pending receipt of simultaneous initial briefs. On the audited final issues on April 9, 1981, and reply briefs on or before April. 16,. 1981.

ISSUES

Final issues before the Commission in this case are: (1) the Company's compliance with Commission's order in. Case No. 79-040-E-42T, VEPCO's prior-rate case; (2) normalization of the federal income tax benefits resulting from the utilization of accelerated depreciation methods; (3)accounting adjustments; (4) discussion of VEPCO's current operations; and (5) rate design.

DISCUSSION OF THE EVIDENCE

I.

In Case No. 79-040-E-42T, VEPCO's prior rate case, the Commission ordered the Company in its next rate case to: (1) justify the continuation of the water heater differential of $0.195, (2) file a cost of service study by tariff schedule, and (3) file a schedule of time of usage rates. Such order further required the Commission Staff to investigate and examine Company witnesses in the next rate ease on the effect, current or potential, of the litigation settlement between VEPCO and Westihghouse: on fuel expenses. In its July, 1980 filing in this case VEPCO eliminated the water heating discount of $0.195 cents per kilowatt hour which applied to a maximum of 800 kilowatt hours of monthly use. The Company chose to eliminate the discount rather than present a study to justify its continuation (Company Ex. EPH-A, p. 6, 7). Mr. Henry H. Dunston, Jr. sponsored the Company, exhibits and testimony regarding the cost of service study by tariff schedule required by the commission's order in Case No. 79-040-E-42T and the Commission's Rules and Regulations for the Government of the Construction and Filing of Tariffs of Public Utilities and Common Carriers by Motor Vehicle (Company Ex. HHD-A). VEPCO filed a schedule of time of usage rates in compliance with the Commission's order in Case, No. 79-040-E-42T and tendered Mr. E. Paul Hilton and Mr. Kimball at the March 9, 1981 hearing to answer any questions with regard to such study. During Staff's audit in this case it investigated the Westinghouse litigation settlement and reviewed the Company plans to use the settlement to reduce fuel expense. Although the Company did not sponsor any witnesses with regard to its settlement with Westinghouse, the Commission did receive a letter bearing date March; 2, 1981 from VEPCO's Vice President and Comptroller, B. D. Johnson which discussed the Company's treatment of the settlement as a reduction-an fuel expense. Since the Company is using the Westinghouse settlement to reduce fuel Expenses, the Commission is of the opinion that -the accounting treatment the Company plans to utilize would best be reviewed in a fuel proceeding. Therefore, the Commission finds that the Company should more fully present its planned treatment of the Westinghouse settlement and the Commission's Special Studies Division should further investigate and examine such plan and each present their recommendations on this issue to the Commission in the Company's next fuel review proceedings now scheduled for June 22, 1981.

II.

Normalization of the federal income tax benefits resulting from the utilization of accelerated depreciation methods was an issue before the Commission in the interim phase of this case (see page 7 of the Commission's Interim Decision of December 29, 1980 for discussion thereof At the interim hearing, Mr. Heavenridge, Company's witness on the normalization issue, offered to utilize the Company's recently acquired computer simulation model to present the Commission with evidence as to the extent to which normalization could reduce VEPCO's cost of capital. In its interim decision the Commission agreed to allow the Company the opportunity to come in and present such evidence in the final phase of this case.

During the final hearing the Company presented the testimony of D. L. Heavenridge (Ex. DLH-A accompanied by 8 exhibits and one supplement and Linwood R. Robertson (Ex. LRR-B) regarding this issue. Mr. Robertson discussed the advantages of normalization accounting as related to VEPCO's financing program. For the test year 1979 Mr. Robertson stated that VEPCO was able to avoid raising $68 million through the sale of securities at prevailing high rates because it had such amount available in federal income tax deferrals in the various jurisdictions served by the Company, except West Virginia. Such amount would have increased the actual figure of $407 million of securities sold during 1979 by about 17 percent. With the assumption that VEPCO maintained a capital structure of 52 percent debt, 13 percent preferred and 3 5 percent common equity Mr. Robertso calculated that the $68 million would have been raised by about $35 million of debt, $9 million of preferred stock and $24 million of common stock. Mr. Robertson further derived an additional annual interest cost to the Company of about $3.5 million by applying VEPCO's actual interest cost for long term debt sold in 1979 of 10.14 percent to the $35 million of additional debt. Because coverage limitations would have prevented the sale of any additional preferred stock in 1979, the remaining amount would have to be raised through debt or common stock. If such amount had been raised through a common stock issue the Company's earnings per share for 1979 would have been reduced from $1.63 to $1.57. Mr. Robertson further states that the financial community and the security rating agencies would consider VEPCO a better credit risk and its securities could be sold at more attractive rates if it were allowed to utilize normalization accounting. On cross examination Mr. Robertson agreed that the Company's customers, except in West Virginia paid higher rates in 1979 since the Company was authorized to utilize normalization accounting. (Tr., p. 95).

Mr. Heavenridge utilized the Company's new computerized corporate model to calculate VEPCO's overall cost of capital for the years 1981 through 1985 with and without normalization on a company-wide [basis. Mr. Heavenridge calculated an average increase in the cost of capital resulting from the utilization of a flow through method of accounting of about 0.46 percentage points for the five year period (Ex. DLH-B, p. 1-3 and Ex. DLH-5, DLH-6 and DLH-7). Mr. Heavenridge explained that even though the Company's revenue requirement would be increased by normalization that it would be incorrect to assume that normalization would always create a higher revenue requirement. Whether flow through or normalization would produce a higher revenue requirement for any given test period depends on the net effect of either methodology on the rate base and the Company's cost of capital. In the Company's originally filed exhibits in this case it normalized tax deferrals beginning in 1974. Mr. Robertson further filed appropriate revisions to his originally filed exhibits reflecting the commencement of normalization on a prospective basis beginning with the 1979 test period, in this case as proformed for North Anna Unit No. II (Ex. DLH-1, supplemental).

Commission Staff in final phase hearings did not present any evidence over and above that entered of record in the interim phase of this case. Staff recommends that the Commission only allow the Company to include in its cost of service the actual level of tax expense payable by the Company (RPT-1, p. 2 interim phase). On cross examination of Mr. Heavenridge Staff pointed out that VEPCO's utilization of a computer model to compare the effects of both the utilization of normalization accounting and flow through accounting on the Company's cost of capital included assumptions involving VEPCO's proposed construction program, levels of expected revenues and expenses, and assumptions concerning national economic policies as well as projected levels of inflation (Tr., p. 55-58). Mr. Heavenridge further stated that the financial model he used to predict the effects of normalization on the Company's cost of capital cannot predict with certainty VEPCO's future revenue requirements nor whether normalization will actually produce lower rates for VEPCO's customers (Ex. DLH-B, p. 4-6; Tr., p. 61-63). Staff summarized its position on this issue in its brief stating that normalization is not a known and measurable change, that normalization results in conscription of customer capital, and that normalization is, at best, an expensive means to customers of increasing VEPCO's cash flow.

The Commission notes since VEPCO was utilizing a flow through method of accounting in 1969 it does not fall within the congressional mandate of the utilization of a normalization method of accounting as set out in §167(1) of the Internal Revenue Code. The Commission further notes that this issue is the only matter not subject to a Staff and Company stipulation as discussed under Part 3 hereof. As pointed out by Staff and the Commission in its interim order of December 29, 1980 in this case, the Commission has historically set VEPCO's rates using a flow through method of accounting (except for necessity certificates, accelerated amortization of pollution control facilities) and has long adhered to the policy that taxes should be limited to the amounts forseeably payable to the federal government, and no more.

VEPCO has not established to any degree of reasonable certainty that its customers will benefit either in the long run or short run if this Commission were to adopt its recommendation with regard to the utilization of a normalization method of accounting for the purpose of calculating the Company's federal income tax liability. In addition to its arguments presented in the interim phase of this case VEPCO contends that the adoption of a normalization method of accounting (1) reduced its capital requirements by $68 million in the test year in the various jurisdictions served by the Company, except West Virginia and (2) would decrease the Company's cost of capital each year for the next five years by about an average of .46 percentage points. However, as Commission staff pointed out in the interim phase of this case the Company's customers must pay nearly two dollars for each one dollar added to VEPCO's deferred taxes account. Thus, although the Company benefited in the test year in the amount of $68 million in those jurisdictions which allowed the Company to normalize, customers in such jurisdictions contributed nearly $136 million more than what would have been included in their rates if flow through accounting had been used. Upon considering the evidence and, testimony submitted in both the interim and final phases of this case the Commission is of the opinion that the Company has failed to establish that it would be in the public interest for this Commission to allow the Company to utilize a normalization method of accounting in calculating its federal income tax liability. Therefore, the Commission will continue to require VEPCO to utilize a flow through method of accounting in computing its federal income tax liability.

III.

At the hearing held on March 9, 1981 VEPCO and Commission Staff executed a stipulation (Company and Staff Joint Exh. No. 1) which in effect resolved all the accounting issues in the case with the exception of the matter relating to normalization. Such stipulation contained the heading Virginia Electric and Power Company, Case No. 80-290-E-42T Stipulation Concerning Increase in Rates and Tariffs, the body of which is as: follows:
Virginia Electric and Power Company, by W. W, Berry, President, and by its counsel, Michael A. Albert and Jackson, Kelly, Holt and O'Farrell, and Guy T. Tripp, III and Hunton and Williams, and the Legal Staff and Accounting Staff of the Public Service Commissions of the west Virginia by Robert W. Geake and Joseph A. Mancuso, Staff Attorneys, and Linda L. Donley, Audit Division, Utility Analyst, hereby agree and stipulate, without prejudice to their respective positions in subsequent cases as to this Company that:

(1) The Operating-Revenue, Operation-and Maintenance Expenses, Depreciation and Amortization of Property Losses, Gain or Loss on Depreciation Of Property, and Taxes Other than Federal Income Taxes shown in the February 26, 1981 Staff Audit Report, Schedule A, Column 7 represent fair and reasonable amounts for those components of the Company's cost of service to be used to set-rates in this proceeding;

(2) The Rate Base amount shown on the Staff Audit Report, Schedule A, Column 7 should be increased from $30,705,474 to $31,101,447 which is a fair and reasonable rate base value-to use for setting rates in this proceeding (subject, however, to reductions described in paragraph (3) below if normalization of certain-federal income tax accounts is permitted); and

(3) With respect to the Provision for Federal Income Taxes, the $ (66,685) amount shown on the Staff Audit Report, Schedule A, Column 7 is correct if the Commission denies the Company's request to permit normalization; but, if the commission permits normalization with respect to facilities placed in service beginning in 1974 the aforementioned $(66,685) would be changed to $230,000 and Rate Base would be reduced to $30,312,447, and if the Commission permits normalization with respect to the test year 1979, as adjusted in this case, then the aforementioned $(66,685) would be changed to $43,000 and Rate Base would be reduced to $31,023,447. It is understood that the Staff continues to oppose normalization, and the above Stipulation of Provision for Federal Income Taxes amounts based on normalization should not be construed as an endorsement of normalization by the Staff.

IV.

The main components of the Company's requested increase in rates are attributable to the inclusion in the rate base for the entire test year of North Anna Nuclear Units I and II and, the increase in the cost of Capital, and inflation of the cost of other goods and services (Co. Exh. WWB-A, p. 10). At the hearing held in the final phase of the case in March of this year the Company presented testimony with regard to its most recent fifteen-year peak load forecast, the commencement of commercial operation of North Anna II Nuclear Unit, the Company's agreement with the Alleghany Power System (APS) for a sale of part of its Bath County Pumped Storage Project, and revealed its decision to continue North Anna Unit III as a Nuclear Unit but to cancel Unit IV (Co. Exh. WWB-B, p. 1-5; Tr. p. 10-35).

In late summer 1980 VEPCO completed a forecast in peak demand for the fifteen-year period 1981-1995 which indicated a compound annual growth rate of 2.1 percent of summer peak load and a 2.8 percent in winter peak load. Wharton Econometric Forecasting Associates, Inc. reduced its 3.1 percent projected real GNP growth for the period 1980-1988 made in December 1978 to a 2.8 percent projected growth in real GNP over a period 1980-1989 as of June 1980. Such lower projections of economic activity combined with increased attention to energy conservation and load management induced reductions in peak load and point to a more modest growth in peak demand in VEPCO's service area during the next fifteen years and accordingly caused the Company to project a lower growth in demand than that contained in previous forecasts.

VEPCO's newest nuclear generating unit, North Anna Unit II, went into commercial operation on December 14, 1980 after commencing start-up procedures in August of the same year. The benefits of the low fuel cost generation available from this 870 megawatt unit is one of the reasons the Company believes that a substantial reduction in system fuel cost is eminent. This downward reduction in rate is expected due to an anticipated improvement in the Company's mix of generation resulting from a program consisting of four major points. The first point involves improved operation of VEPCO's four nuclear units, the newest unit being North Anna No. II just mentioned. It has operated extremely well since its commercial operation, exceeding a capacity factor of ninety percent. North Anna No. I operated at a capacity factor of 76.1 percent in 1980 compared to a national average of about 58 percent. It is now out for refueling. Surry No. 2 completed replacement of its steam generators and other upgrading in August of 1980 which has improved its performance substantially. Its capacity factor has been about 87 percent since the steam generator(s) were replaced. Surry No. 1 is now out for a similar overhaul and replacement of its steam generators. As a result of the above the percentage of VEPCO's power supply from nuclear increased from 17 percent in 1979 to 27 percent in 1980 and is projected to be 40 percent in 1981.

The second point of the Company's program to improve its mix of generation is coal conversion. In February the Company converted its sixth oil-fired unit to coal giving it a total of 1,600 megawatts capacity that has been converted from oil to coal. VEPCO has four additional units in progress totalling 600 megawatts that will be converted by 1983. The Company expects the 25 percent of its generating capacity that came from coal in 1980 to increase to 40 percent in 1981.

Thirdly, VEPCO is seeking to improve the performance of its coal and nuclear generating units. This phase of the program will extend through 1983 and will require significant capital expenditures. The Company's 1981 budget includes spending $137 million on new generating capacity and about $260 million on upgrading existing capacity, including the coal conversion and the performance improvement program.

Through the above mentioned three points VEPCO will have reduced the contribution of oil to its total energy supply, which was about 50 percent in 1972, 33 percent in 1979, down to 19 percent in 1980 and is projected to be down to 10 percent in 1981. VEPCO points out that such changes in its mix of generation will have a profound downward effect on its fuel expenses because coal costs about two cents per kilowatt hour and nuclear energy costs about half a cent per kilowatt hour while oil costs about five cents per kilowatt hour (Tr., p. 14).

For the year 1980 VEPCO's generation mix consisted of 27 percent nuclear, 25.4 percent coal, 19.5 percent oil, 26.7 percent purchased and interchanged power, and 1.4 percent hydro. For 1981 the Company is projecting 41.5 percent nuclear, 40 percent coal, 10 percent oil and the rest hydro and purchased and interchanged power (Tr., p. 31-32).

The fourth and final point in the Company's rate restraint program is a rigorous control of construction expenditures. VEPCO adjusted its construction program to conform with its updated load forecast to assure that it met its customer needs but at the same time does not construct megawatt capacity that is not required or demanded by its customers. VEPCO reached an agreement with Allegheny Power System in October 1980 to sell up to one half of the Bath County Pumped Storage Project and in addition completed a year long study of its North Anna Nuclear Units Nos. III and IV to determine whether such units should be completed as nuclear, converted to coal, or not built at all. The Company arrived at the conclusion that it would continue and complete North Anna, No. III as a nuclear unit (scheduled for operation in 1989), making five nuclear units on its system and that it should cancel North Anna No. IV, scheduled for operation in the early 1990's. Such revision requires the Company to write off about $165 million invested in North Anna No. IV. It is VEPCO's goal to save the capacity that would have been available because of such generating unit through load management, cogeneration and conservation (Tr. p. 15-16).

As the result of a letter of agreement executed in October 1980 between VEPCO and the Alleghany Power System (APS) the latter has the option to participate in the Bath County Pumped Storage Project as either a joint Owner or a major user. APS has the right to purchase up to a 40 percent undivided interest in the completed project. APS may elect, by December 1981, to increase its percentage of ownership to 50 percent. If APS decides to purchase an interest in the project it must purchase at least an amount equal to 50 percent of the value (cost) of the project at December 31, 1979, which would amount to approximately $230 million plus certain carrying charges. Any additional interest which might be purchased will be at a price that will also be sufficient to cover the Company's cost. VEPCO estimates the total cost of the project, scheduled for operation in 1985 or 1986, to be about $1.6 billion.

The arrangements between; VEPCO and APS also provide that at the time of commercial operation of the project APS will purchase the right to use 40 percent (50 percent if APS so elects before December 31, 1981) of the project's capacity for ten years, less any percentage of undivided interest in the project that APS may have purchased as set forth above. The purchase price for capacity will be a negotiated rate, subject to regulatory approval, covering the Company's cost associated with the construction, operation and maintenance of APS's capacity interest plus a reasonable return to the Company. APS will be required to make periodic payments equal to the applicable carrying charges on an amount equal to 50 percent of the December 31, 1979 assets retroactive to January 1, 1980, until such time as APS purchases an undivided interest equal to 50 percent of those assets or, if no purchase is made, until commercial operation of the project. Under either arrangement APS will have the responsibility to provide the pumping power associated with the energy it is to receive from the project. This arrangement has enabled VEPCO to schedule the first three units of the Bath County Project for completion in 1985 with the last three to follow in 1986 (Company Exh. WWB-B, p. 3-5). The above changes in the Company's construction program has reduced its outside financing for the next five years by about $1.1 billion (Tr., p. 16).

VEPCO has also made several management changes. The Company has brought in or made changes in the vice presidents of power operations, personnel and nuclear operations. It has instituted a management incentive program. It has launched a customer stock sale program raising about $6 million. It has reorganized its public affairs department with the institution of customer advisory boards in each of its regional operations to improve public perception of the Company's operations (R., p. 16, 17).

V.

In compliance with Commission's order in Case No. 79-040-E-42T, VEPCO's immediate prior rate case, and as required by the Commission's Rules and Regulations for the Government of the Construction and Filing of Tariffs of Public Utilities and Common Carriers by Motor Vehicle VEPCO submitted the testimony and exhibits of Mr. Henry H. Dunston, Jr., regarding the required cost of service study by tariff schedule (Co. Exh. HHD-A). In the Company's last rate case it filed two sets of allocation methodologies, average and excess and peak responsibility. Since the Commission utilized the peak responsibility method in the Company's last rate case both of the studies submitted in Statement E of the Company's Rule 42 were performed using the methods that were used by the Commission Staff or that were approved by the Commission in the Company's last rate case (Company Exh. HHD-A, HHD-1, and HHD-2; Tr., p. 73). Mr. E. Paul Hilton, Director of Rate Design for VEPCO, presented the recommended distribution of the proposed increase in rates to the various rate schedules of the Company (Co. Exh. EPH-A). Mr. Hilton first subtracted the increase in unbilled revenue from the Company's requested increase in rates to obtain the amount of the increase to be derived from all of the numbered rate schedules.

Mr. Hilton determined the increase in rates for Schedule 26, Outdoor Lighting Service, by utilizing Mr. Dunston's latest cost study for lighting and applying such prices to the number of lamps in service to determine the Company's proposed revenue for Schedule 26. This calculation resulted in an increase to Schedule 26 - Outdoor Lighting Service, of $42,732 or approximately 21 percent and to Schedule 26 - Street Lighting Service, of $34,555 or approximately 32 percent. These amounts were then subtracted from the balance of the Company's proposed revenue increase which left a balance to be spread over the remaining numbered rate schedules. The prices for certain lamps already at the cost level as provided by Mr. Dunston were not increased. Mr. Dunston also eliminated all of the incandescent lamps from Schedule 2 6 since all of such fixtures have been removed. VEPCO also recommends that its offering of 11,000 33,000 and 53,000 lumen mercury vapor lamps and all urban lights be closed. The Company believes that the elimination of new installation of these lamps represents technological progress and should result in reductions in operating expenses because of (1) the almost nonexistance in requests for these lamps and (2) such type of lamps are of the less efficient light source class in relation to the high pressure sodium vapor lights.

The balance of the Company's requested rate increase after making deductions for the increase in unbilled revenue ($13,848) and the increases applied to Schedule 26 as discussed in the above paragraph were spread among the remaining rate schedules. Mr. Dunston's class rate of return study was reviewed after annualizing for VEPCO's most recent rate increase in Case No. 79-040-E-42T. The Company then reviewed and determined the revenue effect from billing its Schedule 30 and traffic customers on Schedule 5. VEPCO concluded that it was appropriate for its Schedule 30 and Schedule 5 customers to be billed at the same rate level because the type of services under such schedules were very similar. The Company, based on its review of Mr. Dunston's study, applied a full share of the remaining increase to Schedules 1 and 6, a half share to Schedules 5, 7 and 42, and a half share plus the revenue effect from billing its Schedule 3 0 and traffic customers on Schedule 5 to the Company's Schedule 3 0 and traffic customers. This allowed the respondent to design Schedule 5 and apply such new rate to Schedule 30.

In response to the question on cross examination as to what the Company's criteria was for applying a full share as opposed to half a share, Mr. Hilton stated that the Company looked at the rate of return by class of customers calculated by Mr. Dunston to determine the comparative rates of return between classes under book conditions and found that Schedule 5 was producing a much larger rate of return with existing rates than were Schedules 1 and 6. Thus the Company, in order to narrow this difference in rate of return by class, decided to apply only half of the percentage increase to Schedule 5 as it did to the other schedules. It was also discovered on cross examination of Mr. Hilton that the cost of service study performed by Mr. Dunston and filed as an exhibit in this case (Co. Exh. HHD-2, Statement E, Part B, Schedule 1, Page 1 of 1) was not the exhibit used by Mr. Hilton in designing VEPCO's proposed rates (Tr., p. 78-80). Mr. Hilton stated that Mr. Dunston's exhibit had the accounting adjustments that were applicable to the rate case and that the rate of return statement that he (Mr. Hilton) used that was calculated by Mr. Dunston did not have such adjustments and, further, that such latter schedule had not been filed in this case. Mr. Hilton stated that the figures on which he relied did not have the rate case adjustments and that they were at a higher level than if they had included such adjustments. Before the increase was applied Mr. Hilton relied on the following class rate of return figures: Residential at 3.8%, Small General Service at 8.5%, and Large General Service at 4.6%. After the increase was applied Residential became 9.7%, Small General Service became 12.25%, and Large General Service became 12.55% (Tr., p. 80-81).

Other changes in rate design as proposed by the Company by tariff schedule are as follows:

SCHEDULE 1 - RESIDENTIAL SERVICE

The basic customer charge and the KWH charge were increased to more accurately reflect cost. The water heater discount was eliminated and a line extension paragraph added because of the elimination of Schedule 19 - Rural Extension Plan. The Company applied a ten-to-one revenue ratio toward the cost of providing service to residential customers. VEPCO believes such ratio will allow it to continue to provide service at no cost to normal service installations and at the same time prevent an undue burden on the Company's other customers resulting from requests for service that are of great length or of questionable revenue. The first three changes being made in paragraph 2 and the final change in paragraph 4 of Schedule No. 1.

SCHEDULE 5 - SMALL GENERAL SERVICE

The following changes were made in paragraph 2 of such schedule: the basic customer charge in the over-100 KW charge was increased to more accurately reflect cost; the KWH charge was increased and the number of blocks reduced for simplification; and the minimum charge was increased to $3.00 per KW.

SCHEDULE 6 - LARGE GENERAL SERVICE

In part C of paragraph 2 the Company changed the block “first 255,000 KWH and any additional KWH up to 255 KWH per KW of demand” to “first 210,000 KWH and any additional KWH up to 210 KWH per KW of demand.”

In part B(1) of paragraph 3 the schedule's on-peak hours were changed to conform with Company's on-peak hours. In part C of paragraph 7 the charge per KW of demand for breakdown, relay or parallel operations service was changed to equal the charge per KW shown in the second block of the demand charge in paragraph 2, part A.

SCHEDULE 7 - ELECTRIC HEATING

This schedule is a companion rate in that the customer receives services for lighting and for purposes other than space or water heating or clothes drying on either Schedule 5 or Schedule 6. VEPCO did not seek to include a basic customer charge in this schedule but will retain the provision for a minimum charge which has been in effect for several years. The demand prices were set at the same level as were determined for Schedule 42, the minimum charge was made equal to the Schedule 5 customer charge, and the remaining revenue needed was applied to the energy price per KWH. There was no revenue effect from setting the demand prices at the derived Schedule 42 KW demand charges because there were not any Schedule 7 customers whose demand exceeded 100 KW.

SCHEDULE 19 - RURAL EXTENSION PLAN

VEPCO eliminated the schedule and added a paragraph in Schedule No. 1 to compensate therefor. The Company did not have any customers on this schedule at the time of the filing of this case and did not anticipate any in the near future, thus its elimination was requested.

SCHEDULE 30 - COUNTY OR MUNICIPAL ELECTRIC SERVICE

After reviewing the rate of return by classes on rates effective March 15, 1980 and comparing the revenue effect of billing Schedule 30 customers on the March 15, 1980 rates, the Company decided to apply the rates as designed for proposed Schedule 5 to its Schedule 30 but without the small KW demand cut off. The Company believes since customers of each schedule have similar load characteristics they should be billed at the same rate.

SCHEDULE 42 - COUNTY OR MUNICIPAL ALL-ELECTRIC BUILDING SERVICE

The Company set the energy charge at the same price as it determined in Schedule 7. The basic customer charge was increased to $7.50 to more accurately reflect cost. The amount of revenue needed from demand charges was calculated and distributed on a dollar per KW basis.

Prices included in the Company's proposed rate design reflect the 0.276 cents per KWH fuel roll-in which became effective with the billing month of July, 1980.

In his final exhibit Mr. Hilton described the revenue increase per tariff schedule and the related percentage increases (Co. Exh. EPH-3). Such information is summarized as follows:

	($) Increase	(%) Increase
Schedule 1 - Residential Service	$2,052,052	28.1
Schedule 5 - Small General Service	285,103	14.2
Schedule 6 - Large General Service	533,001	27.1
Schedule 7 - Electric Heating	5,801	13.7
Schedule 26 - Outdoor Lighting Service	42,732	21.3
Schedule 26 - Street Lighting Service	34,555	32.4
Schedule 30 - County or Municipal Electric Service	70,282	18.5
Schedule 30 - Traffic Control Service	275	17.5
Schedule 42 - County or Municipal All-Electric Building Service	13,329	14.0

Commission Staff did not submit evidence with regard to the issue of rate design. Commission's interim decision of December 29, 1980 followed the Company's proposed rate structure but was appropriately scaled downward in order to achieve the revenue requirements as determined therein.

SUMMARY

The Commission is of the opinion and finds that VEPCO's cost of service allocated to its West Virginia jurisdictional business is $14,746,707[*], that interim revenues including fuel are generating $14,673,730 (Staff Exh. LLD-1, Statement A, Schedule 1), and that there exists a small deficiency in interim revenues of about $72,977, all as developed in Appendix A attached hereto. For purposes of this case the Commission is of the opinion that the revenue level approved at the interim phase of this case and spread to the various tariff schedules of the Company are just and reasonable and should be adopted and approved on a prospective basis as the final revenue level in this case. All tariff schedules filed by the Company pursuant to the interim order in this case are hereby approved with the exception of Schedule No. 6 which has been modified as requested by VEPCO in its original filings of July, 1980, and as contained in the direct testimony of Mr. E. Paul Hilton (Co. Exh. EPH-A, Tr., p. 77).

The rates and charges approved herein include an authorized rate of return of 10.41%. Such return should give the Company an opportunity to earn a 14.5% return on common equity. The increase granted in this case should further allow the Company to meet its operating and maintenance expenses, its federal income tax liability, its financial obligations and to carry forth its construction program.

The cost of service, attached to the interim order as Appendix A in this matter, included a $24,000 error made by Staff in its bill analysis in the interim phase of this case and further included a portion of the total fuel costs in the amount of about $337,000 (Tr. pp. 109-126)

In VEPCO's most recent fuel review case (Case No. 80-467-E-GI), the Commission approved a Company and Staff stipulation with regard to the appropriate fuel cost component to be included in the Company's rates. The stipulation, in effect, made no change in the fuel cost component in the tariffs filed by VEPCO in this rate case. Before adjustment for B&O taxes such fuel cost component in the amount of $0.01945 per KWH sold included purchased and interchanged power.

FINDINGS OF FACT

Based on all the evidence presented in this case, the Commission makes the following findings:

1. Company and Staff Joint Exhibit No. 1 stipulating the accounting issues in this matter is a just and reasonable resolution of such issues for the purpose of this case (Company and Staff Joint Exh. No. 1). Staff proforma adjustment No. 55 is reasonable and reflects the Commission's decision with regard to uncollectible accounts (Staff Exh. LLD-1).

2. It is reasonable that VEPCO only be allowed to include in the rates it charges to its customers the actual amount of its federal income tax liability due and owing the Internal Revenue Service (Company Exh. DLH-A; LRR-B; Tr., pp. 53-72, 93-96; Staff Exh. RPT-1, interim phase).

3. The Company's proposed method of treatment of its Westing-house settlement to reduce fuel expense will be addressed in depth in the Company's next fuel review proceeding scheduled for June 22, 1981.

4. The rates and charges approved in the interim phase of this case, subject to the following paragraph, are hereby adopted as the final rates and charges in this case.

5. VEPCO's Tariff Schedule No. 6 - Large General Service -should be amended to include the following changes:
(a) Part C of Paragraph 2.A the Company should change the block "first 255,000 KWH and any additional KWH up to 255 KWH per KW of demand" to "first 210,000 KWH and any additional KWH up to 210 KWH per KW of demand" and,

(b) Under the heading of Determination of KW Demand B.l on-peak hours of """"10:00 a.m. to 10:00 p.m., E.D.T. (9:00 a.m. to 9:00 p.m., E.S.T.)" shall be changed to "7:00 a.m. to 10:00 p.m., E.S.T. (8:00 a.m. to 11:00 p.m., E.D.T.)". (Co. Exh. EPH-1, p. 10 of 23; Tr., p. 77).

(c) Under the heading Breakdown, Relay or Parallel Operation Service, the rate of "$5.26 per KW demand contracted for under Paragraph VII", should be changed to the rate of "$6.86 per KW demand contracted for under Paragraph VII."

The above changes in Tariff Schedule No. 6 are prospective only. The interim rates and charges are approved as being just and reasonable during the period in which they have been charged and collected.

CONCLUSIONS OF LAW AND ORDER

1. The rates and charges set forth in the Commission's interim order of December 29, 1980, effective as of January 1, 1981, are just and reasonable for the period during which they were collected.

2. The rates and charges set forth in the Commission's interim order of December 29, 1980, effective January 1, 1981, as modified by the changes made in Tariff Schedule No. 6, herein above mentioned, are just and reasonable prospectively from the date of this order for the reason that they will generate revenues at the level needed for VEPCO to pay its reasonable and necessary operating expenses, taxes and depreciation, and earn a fair return on its property used and useful in its business in this state.

3. VEPCO shall file with the Commission within twenty days of the date of this order its tariff schedules containing the rates and charges approved and authorized herein.

4. VEPCO shall file on or before June 8, 1981, in Case No. 81-161-E-GI its proposed accounting treatment for its Westinghouse settlement for Commission Staff's review and recommendation. Commission Staff shall file on or before June 15, 1981, in Case No. 81-161-E-GI its recommendation with regard to the Company's proposed treatment for the Westinghouse settlement.

5. The Executive Secretary of the Commission is directed to serve a copy of this order on Commission Staff by hand delivery and upon all other parties of record by United States Certified Mail, return receipt requested.

AND IT IS SO ORDERED.

<<Signature>>

Commissioner Otis D. Casto
<<Signature>>

Commissioner Elwin Bresette

<<Signature>>

Chairman E. Dandridge McDonald

Footnotes

* Includes Fuel at level approved in Case No. 80-467-E-GI, effective January 1, 1981.

1983 WL 910862 (Va.S.C.C.)

Application of Virginia Electric and Power Company, Applicant and Central Fidelity Bank, Inc., Central Fidelity Bank, N. A., United Virginia Bankshares, Inc., United Virginia Bank, Virginia National Bankshares., Inc., Virginia National Bank, Affiliates, For authority for tax-exempt financing

Case No. PUA820U2

Virginia State Corporation Commission

January 27, 1983

ORDER GRANTING AUTHORITY

By the Commission

THE APPLICANT has filed its application, as amended, for authority under Chapters 3, 4, and 5 of Title 56 of the Code of Virginia, as amended, and the requisite fee of $250 has been paid.

THE APPLICANT represents that it is constructing certain pollution control facilities (the Facilities) at its Yorktown Power Station. The Facilities consist primarily of ash handling and disposal facilities and associated equipment. As in the case of other pollution control facilities financings approved by the Commission, the Applicant proposes to finance these Facilities on a tax-exempt basis.

THE APPLICANT represents that the financing will involve the issuance of promissory notes (Authority Notes) by the Industrial Development Authority of York County, Virginia to several banks, in an aggregate amount of up to $45 million for a term of approximately three years and with an interest rate equal to 65% of the Chase Manhattan Bank's prime rate in effect from time to time (but not to exceed 10% per annum for the first 18 months and 11% per annum thereafter). The proceeds of the Authority Notes will be paid to the Applicant and the Authority will acquire the Facilities, but the applicant retains the right to possess, use and manage the Facilities and the financing will not disturb in any way the continued performance by the Applicant of its duties to the public. Arrangements have also been made for issuance by the Authority of its refunding notes (Authority Refunding Notes) in the form of tax-exempt commercial paper, supported by an irrevocable letter of credit from a nationally prominent bank (the LOC Bank). Repayment of and disbursements under the letter of credit may be extended under a separate revolving credit agreement with the LOC Bank at an interest rate of 103% of the LOC Bank's prime rate. The Applicant will pay the banks for their commitment to purchase the Authority Notes a commitment fee of 1/2 of 1% of the daily average unused portion of their commitment and will pay the LOC Bank a fee of 5/8% of the average amount of tax-exempt commercial paper outstanding. The applicant will issue its own collateral notes as security for the Authority Notes, the Authority Refunding Notes and the LOC Bank's commitment. Central Fidelity Bank, N.A. will act as Trustee in the financing.

THE APPLICANT represents that this proposed transaction will enable the Applicant to finance the capital requirements of the Facilities at a lower interest cost than any available alternative.

THE COMMISSION upon consideration of the said Application, as amended, and representations, and having been advised by its Staff, it is of the opinion that approval of the arrangements described in the Application will not be detrimental to the public interest; accordingly,

IT IS ORDERED:

(1) That the Applicant is authorized under Chapters 3, 4 and 5 of Title 56 to enter into the arrangements described in the Application and the record under the terms and conditions set forth therein;

(2) That the transactions authorized herein shall be accounted for by the Applicant as set forth in the Application and the record; and

(3) That there appearing nothing further to be done, the same be, and it hereby is closed.

End of Document