Large Filing Separator Sheet

Case Number: 99-1729-EL-ETP
99-1730-EL-ETP

File Date: 12/30/99

Section: 3 of 12

Number of Pages: 201

Description of Document: Testimony of Bethel, Knorr, Laine, McCoy, Nelson, Pena
Pyle, Roush
Part A Schedule UND-1

Ohio Power Company
Load Research Year Ended December 31, 1993
Coincident Peak Loads
Generation Level

Pre Rate Restructuring Class Totals

	Loss Adj
GSN Sec	48,124
GSD Sec	429,302
LP Sec	394,264
Total Sec	871,690
GSD Pri	22,826
LP Pri	353,384
Total Pri	376,210
GSD Subtran	8,581
LP Subtran	173,173
Total Subtran	181,754

Post Rate Restructuring Class Totals

	Metered	Adjusted
GS1	53,686	53,694
GS2	368,419	368,473
GS3	449,457	449,523
Total Sec	871,562	871,690
GS2	45,158	45,148
GS3	331,135	331,062
Total Pri	376,293	376,210
GS2	32,802	32,310
GS3	151,717	149,444
Total Subtran	184,519	181,754

Post Rate Restructuring Summary

Customer Class	Average Coincident Peak Demand
RS Sec	1,066,373
GS1 Sec	53,694
GS2 Sec	368,473
GS2 Pri	45,148
GS2 Subtran	32,310
GS3 Sec	449,523
GS3 Pri	331,062
GS3 Subtran	149,444
GS4 Pri	35,408
GS4 Subtran	363,666
GS4 Tran	509,236
EHG Sec	18,128
EHS Sec	655
SS Sec	47,501
OL Sec	1,047
SL Sec	1,554
Total	3,473,222

EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP
In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP

DIRECT TESTIMONY OF
GERALD R. KNORR
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

INDEX TO DIRECT TESTIMONY OF
GERALD R. KNORR
PUCO CASE NOS. 99-__-EL-ETP and
99-__-EL-ETP

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
GERALD R. KNORR
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
CASE NO. 99-__-EL-ETP
AND
OHIO POWER COMPANY
CASE NO. 99-__-EL-ETP

Personal Data

Q. Please state your name, business address and position.

A. My name is Gerald R. Knorr and my business address is 1 Riverside Plaza, Columbus, Ohio 43215-2273. I am an assistant controller of American Electric Power Service Corporation (AEPSC), and certain other subsidiaries of American Electric Power Company, Inc. (AEP).

Q. What are your principal areas of responsibility with AEPSC?

A. I am the director of non-utility ledger accounting. In that capacity, I am responsible for the general ledgers, financial statements and reports, various statistical reports, and accounting practices of AEP, AEPSC, and all the direct non-utility subsidiaries of AEP and certain indirect subsidiaries. My responsibilities include the monthly service billings issued by AEPSC.

Q. Please briefly describe your educational and professional background.

A. I have a Bachelor of Business Administration degree in Accounting from Hofstra University in Hempstead, New York. I am a certified public accountant in New York and a member of the American Institute of Certified Public Accountants and the New York State Society of Certified Public Accountants.

After graduation from Hofstra University I was employed for six years with a major public accounting firm. I began my employment with AEPSC in August 1971 and was elected assistant treasurer in 1974 and assistant controller in 1996. I have held various accounting positions with AEPSC since 1971, including my current position as director of non-utility ledger accounting beginning in 1998.

Purpose of Testimony

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

A. The purpose of my testimony is to address the separate accounting requirements of Am. Sub. S. B. No. 3 (S. B. No. 3) as enacted by the General Assembly of the State of Ohio and the Commission's rules. I am also sponsoring the Company responses to various sections of Part B, Corporate Separation. I present and discuss the accounting procedures and systems that will be used to comply with the separate accounting requirements of The Public Utilities Commission of Ohio (the Commission), including AEP's plan to maintain a cost allocation manual under the Commission's corporate separation rules [Part B, §(G)(2) and §(J)(1)-(9).]

Separate Accounting Requirements

Q. How does S. B. No. 3 address separate accounting requirements?

A. Among other things, Ohio Revised Code Section 4928.17(A)(1) states that a utility's corporate separation plan must include separate accounting requirements for the electric utility and the fully separated competitive retail electric supplier as well as for any fully separated provider of non-electric product or service (the Separate AEP Companies). §4928.18(D)(2) states that "corporate separation" does not prohibit the common use of employee benefit plans, facilities, equipment, or employees, subject to proper accounting and the code of conduct ordered by the Commission as provided in §4928.17.

Q. How do CSP and OPCO intend to comply with the corporate separation requirement of S. B. No. 3 and the Commission rules on corporate separation?

A. As Company Witness Forrester states in his testimony, both CSP and OPCO plan to establish new transmission subsidiaries and new distribution subsidiaries (the New T and D Subsidiaries). The New T and D Subsidiaries will own and operate all the transmission and distribution assets currently owned by CSP and OPCO. CSP and OPCO will continue to own and operate their generating assets. Company Witness Forrester also describes the possibility of establishing a separate competitive retail electric supply affiliate.

Q. Briefly describe how CSP, OPCO, the New T and D Subsidiaries, and the Separate AEP Companies will comply with the separate accounting requirements of Ohio Revised Code Section 4928.17(A)(1) and the Commission's rules.

A. AEPSC, a wholly-owned shared-services subsidiary of AEP, will perform the accounting for all companies, including the Separate AEP Companies. Separate books and records will be kept for each legal entity using shared software systems, equipment, managers, and employees. The accounts and transactions of each entity will be identified through unique business unit numbers or other accounting codes.

The fully allocated cost of the accounting services performed by AEPSC will be billed to CSP, OPCO, the New T and D Subsidiaries, and the Separate AEP Companies either directly when the service provided can be identified with a specific company, or on a shared basis when two or more companies benefit from and share the services provided. The cost of providing such shared accounting services will be proportionately allocated and billed to each company based on allocation factors approved by the Securities and Exchange Commission in connection with its regulatory oversight of AEPSC under the Public Utility Holding Company Act of 1935 (PUHCA).

Q. What types of accounting services will AEPSC be providing to CSP, OPCO, and the other companies?

A. The accounting services will be the same type of services that are presently provided by AEPSC to CSP and OPCO. They will include, among other things, accounting policy and research; payroll, accounts payable and general ledger processing; customer accounting; plant accounting; and tax accounting.

Q. Will security be in place over the shared software systems that will prevent AEP employees from accessing information which would violate the Commission's Code of Conduct?

A. Yes. AEP's computer systems allow security to be placed on sensitive information based on employee ID. Training and education efforts will be conducted to help ensure employees understand the "structural safeguards" part of CSP's and OPCO's separation plan as well as the provisions within the

Commission's Code of Conduct related to customer information and any confidential information.

Q. Does the plan to use AEPSC as the provider of accounting services and to use shared software systems, equipment, managers, and employees achieve separate accounting for CSP, OPCO, the New T and D subsidiaries, and the Separate AEP Companies?

A. Yes. The accounting will be performed by AEPSC, an affiliate separate from the electric utilities and the Separate AEP Companies. Separate books and records will be maintained for each company following generally accepted accounting principles. Accounting personnel in AEPSC as well as employees of the utilities and the Separate AEP Companies who handle or use confidential accounting data will be subject to the code of conduct ordered by the Commission.

Cost Allocation Manual

Q. How do the electric utilities propose to meet the requirements for a cost allocation manual (CAM) in connection with the rules promulgated by the Commission pursuant to Chapter 4928, Ohio Revised Code?

A. The Company Response to Part B, §(J) provides a detailed description outlining how the electric utilities and the Separate AEP Companies will comply with the CAM requirements included in the corporate separation rules.

Q. What will AEPSC's philosophy be in preparing the CAM?

A. Since, for the most part, cost allocation methods and related accounting practices are common among all AEP companies, a single CAM will be maintained for all companies by the corporate accounting department in AEPSC. Information contained in the CAM which is company specific will be clearly identified. Documents required by the CAM which are voluminous, subject to frequent change, maintained in areas of the corporate organization other than the corporate accounting department, and/or do not specifically address cost allocation and related accounting practices will be incorporated in the CAM and made part of the CAM by reference. The items incorporated by reference will be clearly described and the group(s) or individual(s) responsible for each item will be identified in the CAM. A clear trail will be maintained to enable an auditor to request and review such documents.

Q. Will incorporating certain documents in the CAM by reference inhibit the Commission Staff's ability to review the CAM?

A. No. As previously stated, all documents incorporated in the CAM by reference <u>will be part of the CAM</u> and as such will be available for Staff review. Certain documents, such as job descriptions for transferred employees, are maintained by groups outside of accounting or are maintained for employee reference purposes in separate databases. Incorporating such documents in the CAM by reference avoids the cost of maintaining and keeping current two sets of records for the same thing. Nonetheless, the separate documents (or electronic databases) will be considered part of the CAM.

Q. Will the documents included in the CAM by reference be subject to the periodic reporting requirements established by the Commission's rules?

A. Yes. A summary of the changes in the CAM, including changes to those documents incorporated by reference, will be sent to the Director of the Utilities Department of the Commission as required by the Commission's rules.

Q. Can you briefly describe the elements of AEP's proposed compliance plan related to the CAM?

A. As previously stated, a single CAM will be developed and maintained for all of AEP's electric utilities, including the Ohio utilities. The CAM will be an indexed compilation of all the descriptions and documents required by the CAM rules. Certain self-contained documents will be incorporated in and made part of the CAM by reference. The actual text of the CAM will describe how costs are allocated and billed between the electric utility companies and any of the Separate AEP Companies with which they do business. The CAM will be maintained on behalf of the electric utility companies by AEPSC.

The CAM, in describing how costs are allocated among companies, will provide information that can be reviewed by the Staff of the Commission to determine that the cost allocation practices followed by the companies do not result in cross-subsidization between the electric utilities and the Separate AEP Companies. The cost allocation guidelines included in the CAM will contain a prohibition against subsidization of non-regulated operations by regulated operations.

The text of the CAM, or related exhibits, will describe the general purpose of each affiliate of the electric utility companies. A description of the types of assets, products and services provided to and from the electric utilities and their affiliates will be included in the CAM along with a corporate organization chart.

Job descriptions for employees who have either transferred to a Separate AEP Company from the electric utility or are shared with a Separate AEP Company will be incorporated in the CAM by reference. Job descriptions are not maintained for consultants, independent contractors or any other persons other than actual employees of the electric utility or the Separate AEP Companies. A list of the names of such persons who have either transferred to a Separate AEP Company from the electric utility or are shared with a Separate AEP Company will be incorporated in the CAM by reference along with the identities of their employers. A log of all complaints brought to the utility regarding the Commission's corporate separation rule (Part B) and copies of the minutes of meetings of the board of directors will also be incorporated in the CAM by reference.

The methods for charging costs and transferring assets shall be based on fully allocated costs for services and products and embedded costs (i.e., net book value) for assets in accordance with Rules 90 and 91 promulgated by the SEC under the PUHCA . The formal cost allocation guidelines contained in the CAM shall require, among other things, that an audit trail be maintained for all recorded transactions which will allow costs, both direct and indirect, to be traced through the accounting systems to the corporate entities who benefit from the costs.

Minimum retention requirements for underlying affiliate transaction information will be documented either in the text of the CAM or by reference. In no case will the retention requirements be less than the three years required by the Commission's rules.

A summary of changes in the CAM, including a summary of changes to the documents incorporated in the CAM by reference, will be provided to the Director of the Utilities Department of the Commission (or their designee) every six months as required by the Commission's rules. The summary will use a caption layout. The captions for the subject (or document) will appear in the left margin of each page and the description of the changes will appear in the blocks of text opposite the caption on the right-hand side of the page. Other page layouts may be employed as appropriate.

AEPSC, on behalf of its Ohio electric utilities, will provide the Commission Staff with the name, telephone number, fax number and e-mail address of the employee who will be the Staff's primary contact concerning CAM matters. The same information may be provided for secondary contacts depending upon the subject matter and the nature of the Staff's inquiry. AEPSC will update the Staff of changes in the contacts.

Q. Are the SEC's Rules 90 and 91 under PUHCA for affiliate transactions consistent with the undue preference compensation requirements of Ohio Revised Code Section 4928.17(A)(3)?

A. Yes. The SEC's rules embrace fully allocated costs which are fairly and equitably allocated. Ohio Revised Code Section 4928.17(A)(3) requires the use of fully loaded embedded costs. The definition of fully allocated costs (i.e., the sum of direct costs plus an appropriate share of indirect costs) contained in the Commission's rules is consistent with the SEC's "at cost" standard for the pricing of affiliate transactions under Rules 90 and 91.

Q. Will AEPSC perform compliance reviews related to the CAM?

A. Yes. AEPSC's Internal Audit Department will periodically perform compliance reviews. The focus of the reviews will be to determine if the CAM is being properly maintained relative to the Commission's rules and that the related reporting requirements are being met.

Q. Will the compliance reviews performed by AEPSC's Internal Audit Department include an evaluation of the cost allocation controls documented in the CAM?

A. Yes. The controls for allocating costs between AEP's non-competitive electric utilities and its affiliates will be evaluated. The review will include, among other things, ensuring that the controls are working and that costs are being appropriately allocated on a fully allocated cost basis.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT NO.________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP
In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP

DIRECT TESTIMONY OF
JEFFRY L. LAINE
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

INDEX TO DIRECT TESTIMONY OF
JEFFRY L. LAINE
PUCO CASE NOS. 99-___-EL-ETP and
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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
JEFFRY L. LAINE
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
CASE NO. 99-___-EL-ETP
AND
OHIO POWER COMPANY
CASE NO. 99-___-EL-ETP

Personal Data

Q. Please state your name and business address?

A. My name is Jeffry L. Laine. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. Please indicate by whom you are employed and in what capacity?

A. I am the Director, Customer Choice Implementation for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP) the parent of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCO).

Q. Please briefly describe your educational background and business experience?

A. I was employed by AEPSC after graduating from the City College of New York in 1971 with a Bachelor of Engineering Degree in Electrical Engineering. I worked as an engineer in the Distribution Engineering Section for five years, and during that time, I earned a Masters Degree in Business Administration from Adelphi University, New York in 1975 and completed the General Electric Company Power Systems Engineering Course in 1976.

From 1976 through 1979, I served as Administrative Assistant to the Vice Chairman - Operations of AEPSC. In 1979, I was promoted to Staff Engineer in the Regional Power Supply Planning Division and in 1981 was appointed as Section Manager of the newly-created Load Research & Load Management Section. I attended the AEP Management Development Program conducted at the University of Michigan in 1981. From 1981 through the fall of 1998, although the title of my organizational unit changed, my responsibilities remained fairly stable. They included establishing and directing AEP System load research programs to provide the required data and analysis for various rate, planning engineering and demand-side management (DSM) applications. My responsibilities also included the collection and editing of all load research data and the preparation of billing determinants for many customers. Additional responsibilities included directing the evaluation of DSM programs and participating in their planning across the AEP System.

Q. Briefly, describe your current responsibilities.

A. In recognition of the need to provide dedicated Company resources to the challenges of implementing Customer Choice, in September 1998 AEPSC established the Customer Choice Implementation Organization and I was promoted to the position of Director, Customer Choice Implementation at that time. My responsibilities include ensuring that all the required policies, systems, procedures and processes are in place for the successful implementation of Customer Choice on the AEP System.

In 1994 I was appointed as a member of the Association of Edison Illuminating Companies (AEIC) Load Research Committee and was selected to serve as chairman of that organization from the fall of 1998 though the end of the year 2000. The AEIC Load Research Committee promotes responsible load research activities in the electric utility industry, including applications relative to customer choice such as load profiling and market settlement.

Q. Have you previously submitted testimony as a witness before any regulatory commission?

A. Yes. I have testified before the state regulatory commissions of Virginia, West Virginia, Ohio, Indiana and Michigan.

Purpose of Testimony

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

A. The purpose of my testimony is to sponsor Part C of the Transition Plan Filing, briefly describe the Company's approach for developing Operational Support Systems (OSS) and describe the costs associated with implementing Customer Choice.

Operational Support Systems Plan

Q. Please describe the Company's OSS Planning effort.

A. The timeline submitted in response to Part C §(B) includes activities the Company has already completed along with future activities yet to be completed by the Company. The entire project timeline is presented to show the significant amount of effort the Company has expended in planning for Customer Choice prior to this proceeding. As will be described in more detail later in my testimony, the Company is considering a variety of options relative to the implementation of the information technology infrastructure. The future activities included in the timeline identify the set of activities associated with only one of several possible solution paths and are subject to change as specific decisions are made. The responses to Part C §(C) were developed using the planning insights the Company developed prior to the release of the rules established for this proceeding.

Q. What has been the Company's Customer Choice planning process?

A. In order to appropriately prepare for Customer Choice, AEP conducted a detailed exercise which included defining various potential roles and responsibilities of each of the market participants, identifying the major new functions required by Customer Choice and exploring different ways these new functions might be implemented

Q. How was the OSS Planning process developed?

A. The Company began development of a Customer Choice implementation planning process in September 1998 with the formation of the Customer Choice Implementation Division (CCI). The first phase of the process was to develop a broad understanding of the issues and a potential information technology (IT) and solution path for Customer Choice. This involved meetings with employees from a large number of business units from across the Company that could be affected by Choice. Discussions centered on future requirements for choice along with capabilities of current systems to determine where new functionality or systems may need to be developed.

During the second phase of the process the Company developed a set of positions leading to the development of a Customer Choice framework for future decision making. The functional requirements of systems were developed which will allow AEP to evaluate various solution paths for the implementation of Customer Choice. The functional requirements were developed with the input of knowledgeable business unit participants, who are a crucial element in the eventual success of the Company's implementation of Choice.

Currently the third phase of the process is underway. During the third phase the Company will: 1) assess the responses to a comprehensive Request for Proposal (RFP) on an IT solution path, 2) decide on an interim plan to allow Customer Choice to be implemented January 1, 2001 and 3) decide on a more permanent solution that will allow Customer Choice to be implemented in the most cost-effective manner possible.

Q. Will the IT solution path to be followed be the one which was specified in the RFP?

A. Not necessarily. Among the possible solution paths that the Company is considering are the more traditional approach of building an internal IT infrastructure that would serve only AEP's needs, along with an option that provides the same basic functionality through what might be described as a more collaborative approach. The collaborative approach establishes a type of market processing center where several utilities could make use of the same IT infrastructure. It is commonly being called a "Clearinghouse" and in some visions it is a simple transactions processing center and in other visions it includes the functionality to perform such activities, as well as customer enrollment/switching, service provider registration and retail settlement. The Company is investigating the viability of a clearinghouse. If multiple utilities, and potentially other parties as well, could reach agreement on the construction and operation of a shared IT infrastructure, it seems reasonable that customers and market participants throughout the state could benefit through what appears to be a more cost-effective solution.

Q. When will the Company know which IT solution path and business model it will implement?

A. Due to the very complicated nature of the business relationships which must be established to operate a clearinghouse in the yet-to-be-defined world of Customer Choice, commitments to a clearinghouse might not be possible prior to the end of the first quarter of 2000.

Q. Will it be possible for the Company to be ready to implement Customer Choice in Ohio on January 1, 2001 if a decision is not made on the Clearinghouse until the first quarter of 2000?

A. Yes. As mentioned earlier, the Company is investigating potential interim solutions that would provide sufficient functionality until the more permanent solution could be operational.

Q. Are there operational support issues that still need to be addressed in AEP's planning process?

A. Yes. There are a large number of additional elements that need to be addressed prior to Customer Choice becoming an operational reality in Ohio. Many of these elements relate to business rules and practices that must be put in place for the various market participants to be able to conduct business with each other. The Commission has recently identified the need for work groups to resolve Operational Support Plan issues.

Implementation Costs

Q. How did the Company develop its estimate of implementation costs?

A. As I described earlier, there are a variety of implementation options that the Company is considering. The Company intends to implement the option which provides the most cost-effective solution for the required functionality, but until that decision can be made, the implementation costs presented here should be treated as a "place holder." The implementation costs were estimated based on the RFP solution path and developed based upon what has been learned in our planning process to date. The implementation costs represent estimated incremental costs the Company will incur to implement Customer Choice in the marketplace.

The annual costs include such activities as: customer support, service provider support, meter service provider (MSP)/meter data management agent (MDMA) certification, load profiling processing, settlement processing, EDI transactions, employee education and ongoing IT O&M expenses. The IT infrastructure costs were developed based on the Company's functional requirements and IT architectural design developed during the second phase of the overall process previously described. It includes costs to develop new systems along with modification of existing systems and the integration of all those systems. Based on current legislation, Customer Choice will be implemented in Ohio and Virginia, thus the cost would be shared among CSP, OPCO and APCO-VA. The cost estimate does not include expenditures for any unregulated businesses the Company may participate in.

Q. What is the Company's estimate of implementation costs?

The range of options, as well as the uncertainty of the Clearinghouse at this point in time, makes it clear that the implementation costs that are provided in this testimony will have to be adjusted when the actual solution path has been determined. As can be seen on EXHIBIT NO. ___JLL – 1, the estimate for CSP is $55,190,000 for the first five years. EXHIBIT NO. ___JLL – 2 shows the estimate for OPCO is $59,741,000 for the first five years.

Q. Earlier in your testimony you described the possibility of the Company participating in a clearinghouse to help share costs among multiple utilities. How would this approach affect the estimated implementation costs provided in EXHIBIT NO. ___JLL – 1 and EXHIBIT NO. ___JLL – 2?

A. At this point in time, it is impossible to give an accurate answer to that question because the business model for the cost sharing of the construction and operation of the Clearinghouse, if it were to be established, has not yet been determined. At the most basic level, it is reasonable to assume that if other parties were to share the cost of the common elements of the IT infrastructure, those costs would be reduced for the Company. An appropriate adjustment will be made to this filing when, and if, an alternative IT solution path is chosen.

Q. Does this conclude your direct testimony?

A. Yes it does.

Columbus Southern Power Company
Estimated Customer Choice Implementation Costs

	Ohio Costs	Allocation	Annual CSP Estimate
Customer Support	$ 2,250,000	48.05% (1)	$ 1,081,236
Service Provider Support	$ 180,000	48.05% (1)	$ 86,499
Load Profiling Processing	$ 37,500	48.05% (1)	$ 18,021
Settlement Processing	$ 120,000	48.05% (1)	$ 57,666
MSP/MDMA Certification	$ 60,000	48.05% (1)	$ 28,833
EDI Transactions	$ 2,000,000	48.05% (1)	$ 961,098
Employee Education	$10 per employee		$ 15,000
On-going IT O&M Expense	20% of development cost		$ 4,228,833
Annual Total			$ 6,477,186
Number of years			5
Total for five years inflated at a rate of 2.5% per year			$ 34,046,217
IT Infrastructure Costs (below)			$ 21,144,165
Total Customer Choice Implementation Costs			$ 55,190,382

IT Infrastructure Costs	$ 44,000,000
Allocation % (below)	48.05% (1)
CSP Portion	$ 21,144,165

Allocation Percentage:

(1) CSP Customers	12/98 Fin Rpt	630,000
Ohio Customers	12/98 Fin Rpt	1,311,000
Percentage		48.05%

Ohio Power Company
Estimated Customer Choice Implementation Costs

	Ohio Costs	Allocation	Annual OP Estimate
Customer Support	$ 2,250,000	51.95% (1)	$ 1,168,764
Service Provider Support	$ 180,000	51.95% (1)	$ 93,501
Load Profiling Processing	$ 37,500	51.95% (1)	$ 19,479
Settlement Processing	$ 120,000	51.95% (1)	$ 62,334
MSP/MDMA Certification	$ 60,000	51.95% (1)	$ 31,167
EDI Transactions	$ 2,000,000	51.95% (1)	$ 1,038,902
Employee Education	$10 per employee		$ 32,000
On-going IT O&M Expense	20% of development cost		$ 4,571,167
Annual Total			$ 7,017,314
Number of years			5
Total for five years inflated at a rate of 2.5% per year			$ 36,885,308
IT Infrastructure Costs (below)			$ 22,855,835
Total Customer Choice Implementation Costs			$ 59,741,143

IT Infrastructure Costs	$ 44,000,000
Allocation %	51.95% (1)
OPCo Portion	$ 22,855,835

Allocation Percentage:

(1)	OPCo Customers	12/98 Fin Rpt	681,000
	Ohio Customers	12/98 Fin Rpt	1,311,000
	Percentage		51.95%

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DIRECT TESTIMONY OF
HUGH E. MCCOY
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INDEX TO DIRECT TESTIMONY OF
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BEFORE
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CASE NO. 99-___-EL-ETP
AND
OHIO POWER COMPANY
CASE NO. 99-___-EL-ETP

Personal Data

Q. Please state your name, employer, and business address.

A. My name is Hugh E. McCoy. I am employed by American Electric Power Service Corporation (AEPSC) at 1 Riverside Plaza, Columbus, Ohio 43215.

Q. Please outline your educational and professional experience.

A. I graduated magna cum laude from West Virginia University in 1977, with a Bachelor of Science in Business Administration degree in Accounting. From 1977 to 1981, I was employed by Peat, Marwick, Mitchell and Co., ultimately as an Audit Supervising Senior. I have been a Certified Public Accountant since 1979 and am a member of the American Institute of Certified Public Accountants.

Since 1981, I have been employed by AEPSC, initially as a Staff Accountant and later as a Senior Staff Accountant, both in Accounting Policy and Research. In 1998, I was promoted to Manager of Utility Ledgers. In this position, I am responsible for maintaining the books of account and preparing the financial statements of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCO).

Q. Have you previously testified before any regulatory commissions?

A. Yes. I have previously testified before the Public Utilities Commission of Ohio, the Indiana Utility Regulatory Commission, the Michigan Public Service Commission, the Tennessee Public Service Commission, the Virginia State Corporation Commission, the Public Service Commission of West Virginia, and the Federal Energy Regulatory Commission, primarily relating to the accounting for postretirement benefits.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the amount of projected net regulatory assets and other transition costs of CSP and OPCO to be recovered in accordance with the provisions of Am. Sub. S. B. No. 3, as addressed by Company Witness Forrester. In this regard, I will support the projected unrecovered balances of generation-related, Ohio retail jurisdictional net regulatory assets and other transition costs of CSP and OPCO as of December 31, 2000. In addition, my testimony will support the amount of generation-related, Ohio retail jurisdictional regulatory asset recovery in the current rates of CSP and OPCO and show how those recoveries are projected to reduce the December 31, 2000 unrecovered balances of net regulatory assets and other transition costs during the five-year Market Development Period. My testimony also will support the amount of the remaining balances of net regulatory assets and other transition costs as of December 31, 2005 and show how those amounts are to be recovered over the succeeding five years. Further, I will request specific language from the

Commission that will confirm for financial accounting purposes the existence of these generation-related, Ohio retail jurisdictional regulatory assets and their recovery in regulated rates, so that CSP and OPCO can maintain these balances on their books and avoid a premature write-off of these regulatory assets in their general purpose financial statements. Finally, I am sponsoring for CSP and OPCO schedules, reports and responsive statements required by Part F of the Commission's Rules for Electric Transition Plans, specifically Part F, §(B)(1)(a), Regulatory Assets; Part F, §(B)(1)(b)(i) through (iii), Nuclear Costs, Part F, §(B)(1)(c), Regulatory Assets Related to Generation Sold or Transferred; Part F, §(B)(2)(a)(i)(a), Generation Plant in Service; Part F, §(B)(2)(a)(i)(b), Generation Plant in Service Additions and Retirements; Part F, §(B)(2)(a)(ii)(a), Generation Plant in Service Depreciation Reserve; Part F, §(B)(2)(a)(ii)(b), Generation Plant in Service Depreciation Reserve Activity; Part F, §(B)(2)(ii)(c), Depreciation Reserve Allocation, Part F, §(D), Accounting Adjustments, Part F, §(E), Refunctionalization, and Part F, §(F)(2) through (F)(7), Various Financial and Audit Reports.

Net Regulatory Assets

Q. What are the projected generation-related, Ohio retail jurisdictional net regulatory assets balances as of December 31, 2000?

A. The schedules on CSP's and OPCO's respective Part F, §(B)(1)(a), Page 1 of 3, show CSP's and OPCO's projected remaining unrecovered net regulatory assets as of December 31, 2000 on a generation-related, Ohio retail jurisdictional basis .

The schedules also show the recorded amounts of these items as of December 31, 1998, the projected balances as of December 31, 1999, and the projected net changes during 1999 and 2000.

Q. Please discuss each projected net regulatory asset as of December 31, 2000.

A. The first regulatory assets for CSP and OPCO are customer receivables for federal and state income taxes related to Statement of Financial Accounting Standards (SFAS) 109, *Accounting for Income Taxes*. The amounts of these regulatory assets, which result from the prior Commission treatment of flowing through income tax benefits to reduce current rates, were provided to me by Company Witness Bartsch.

Q. Please describe CSP's Zimmer-related items.

A. CSP has two regulatory assets related to the rate treatment in Case No. 91-418-EL-AIR of the then recently completed Zimmer Plant. In that case, the Commission authorized the recording, for future recovery in CSP's next general rate proceeding, of Zimmer embedded interest incurred after the in-service date but prior to the effective date of the rates resulting from that case. Since Zimmer embedded interest was recorded on a net-of-tax basis, the amount shown for this item on the list of regulatory assets must be grossed-up for income taxes to reflect a revenue requirement level. This income tax gross-up has been included in the amount of customer receivables for federal income taxes, so that the total of all items on the list is on a revenue requirement basis. The Commission also provided for the deferral and recovery over ten years, beginning with the effective date (May 1992) of the rates resulting from that case, of Zimmer operating and maintenance costs incurred after the in-service date but prior to the effective date of the new rates.

Q. What is CSP's regulatory liability for deferred phase-in revenues?

A. Phase-in revenues deferred in conjunction with Case No. 91-418-EL-AIR were over-recovered through a load-based charge because the actual load during the recovery period exceeded the projected amount. The over-recovery is a regulatory liability.

Q. Please describe OPCO's deferred fuel cost regulatory asset.

A. OPCO has a regulatory asset for deferred fuel cost related to the stipulations in its fuel clause cases. The forecasted balance was provided to me by Company Witness Nelson.

Q. What are the PIPP and SFAS 112 regulatory assets?

A. CSP and OPCO have Percentage of Income Payment Plan (PIPP) arrearages, which are the amounts of unrecovered PIPP costs. The projected amounts were provided to me by Company Witness Forrester. Next, CSP and OPCO have regulatory assets for postemployment benefits recorded in accordance with SFAS 112, *Employers' Accounting for Postemployment Benefits*. These benefits are related to health care and life insurance continuation for employees who are on long-term disability. These costs are required by SFAS 112 to be accrued for financial reporting purposes, but they are deferred as a regulatory asset because they have been and continue to be treated by the Commission on a cash basis for ratemaking purposes.

Q. Please describe OPCO's regulatory asset for VEBA trust contributions.

A. OPCO's postretirement benefits VEBA trust contributions relate to pre-1995 contributions that were deferred and amortized for recovery over ten years beginning March 1995 in Case No. 94-996-EL-AIR.

Q. What are the final listed regulatory assets?

A. CSP and OPCO have regulatory assets for unamortized loss on reacquired debt and deferred preferred stock reacquisition costs that are amortized over a future period of years in accordance with Commission approval obtained with each new refinancing authorization.

Other Transition Costs

Q. What type of other transition costs do CSP and OPCO have?

A. CSP and OPCO have other transition costs that are in effect regulatory assets or that result directly from Am. Sub. S. B. No. 3. None of those other transition costs as discussed herein are uneconomic or impaired generating plant costs that are commonly referred to as stranded costs.

Q. What are CSP's and OPCO's other transition costs?

A. The bottom portions of the schedules on CSP's and OPCO's respective Part F, §(B)(1)(a), Page 1 of 3, show CSP's and OPCO's projected generation-related, Ohio retail jurisdictional other transition costs.

Q. Please describe the SFAS 106-related other transition costs.

A. The remaining transition obligation amortization related to SFAS 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, is in effect a regulatory asset which is not included with the regulatory assets discussed above because it is not actually recorded on the books. Generally accepted accounting principles do not allow the recording of either the SFAS 106 transition obligation or the offsetting deferral.

Q. Please explain.

A. When CSP and OPCO implemented accrual accounting for postretirement benefits in accordance with SFAS 106, the Companies elected to recognize the transition obligation as an expense over twenty years rather than expensing the entire amount immediately. The transition obligation represents a catch-up adjustment related to benefits earned by employees and retirees prior to 1993, all of which is properly recoverable from ratepayers.

Q. Please continue.

A. Normally, an item such as this would have been deferred on the books as a regulatory asset and included in the list of recorded regulatory assets discussed above under Net Regulatory Assets. However, in this case, the SFAS 106 rules provide that one-twentieth of the transition obligation be added to postretirement benefits cost each year for twenty years without the unamortized balance being recorded on the Companies' books. As a result, the unamortized SFAS 106 transition obligation is not recorded on the books as a liability or deferred as a regulatory asset for financial reporting purposes. Nevertheless, the generation-related, Ohio retail jurisdictional portion of the remaining unamortized SFAS 106 transition obligation is a legitimate transition cost which has been stranded by the restructuring legislation and should be recoverable through the transition plan.

Q. Please explain the consumer education and customer choice implementation costs included as other transition costs.

A. Am. Sub. S. B. No. 3 requires that the Companies contribute to the cost of a statewide consumer education plan. The projected costs of this plan for CSP and OPCO were provided to me by Company Witness Forrester. Am. Sub. S. B. No. 3 also will cause customer choice implementation costs, which were provided to me by Company Witness Laine.

Q. Please explain the transition plan filing other transition costs.

A. Am. Sub. S. B. No. 3 also causes the Companies to incur the cost of this transition plan filing, which costs were provided to me by Company Witness Forrester. These costs are similar to the rate case expenses for which the Commission provided amortization and recovery in CSP's and OPCO's current rates.

Regulatory Asset Recovery in Current Rates

Q. What regulatory asset amortizations are included in current rates?

A. The schedules on CSP's and OPCO's respective Part F, §(B)(1)(a), Page 2 of 3, show CSP's and OPCO's generation-related, Ohio retail jurisdictional regulatory asset amortizations that are included in current rates. For CSP, current rates are based on Case No. 91-418-EL-AIR, which had a test year ended December 31, 1991. For OPCO, current rates are based on Case No. 94-996-EL-AIR, which had a test year ended March 31, 1995.

Q. What items are included in regulatory asset amortizations in current rates?

A. CSP and OPCO both have in current rates customer receivables for income taxes (SFAS 109), which were provided to me by Company Witness Bartsch, loss on reacquired debt, and rate case expense. CSP also has an amount in its rates to recover the amortization of deferred Zimmer operating and maintenance costs. The amount in OPCO's current rates for the deferred fuel cost, which is related to the stipulations in its fuel clause cases, was provided to me by Company Witness Roush. OPCO's current rates also include recovery of deferred SFAS 106 postretirement benefits cost, deferred postretirement benefits VEBA trust contributions, and the SFAS 106 postretirement benefits transition obligation twenty-year expense recognition discussed above under Other Transition Costs. Additional items in OPCO's rates include amortizations of deferred Gavin scrubber operating and maintenance expenses, deferred Tidd PFBC costs, and deferred demand side management (DSM) costs.

Transition Cost Recovery

Q. How will CSP's and OPCO's transition costs be recovered?

A. The schedules on CSP's and OPCO's respective Part F, §(B)(1)(a), Page 3 of 3, show CSP's and OPCO's transition cost recovery. As discussed in more detail by Company Witness Forrester, during the years 2001 through 2005 recovery of generation-related, Ohio retail jurisdictional regulatory assets and other transition costs is based on the level of regulatory asset amortization in current rates, adjusted for subsequent projected changes in load. The remaining unrecovered balance of each Company at December 31, 2005 is to be recovered through a level kilowatthour charge over the following five years. Company Witness Roush provided me CSP's and OPCO's individual recovery amounts for each year.

Accounting Authorization

Q. Does the Commission's Order in this proceeding have to specifically address regulatory asset recovery in order for CSP and OPCO to maintain their generation-related, Ohio retail jurisdictional net regulatory assets on their books and avoid a write-off for financial reporting purposes?

A. Yes, without sufficient evidence that CSP's and OPCO's specific generation-related, Ohio retail jurisdictional net regulatory assets will be recovered under their respective transition plans, financial accounting rules as promulgated by the Financial Accounting Standards Board would require the Companies to write-off those net regulatory assets to expense, thereby reducing net income and retained earnings. Specific approval in a Commission Order of the amount of generation-related, Ohio retail jurisdictional net regulatory assets and the timing of their recovery in accordance with the recovery plan included in each Company's filing would allow CSP and OPCO to avoid a write-off. Then, as part of each Company's Corporate Separation Plan, as discussed by Company Witness Forrester, CSP and OPCO would be able to transfer these net regulatory assets from their generation business to their distribution business and to amortize those net regulatory assets over ten years in accordance with their recovery in the transition plans.

Q. Does this complete your direct testimony?

A. Yes.

EXHIBIT NO.________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP
In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP

DIRECT TESTIMONY OF
PHILIP J. NELSON
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

INDEX TO DIRECT TESTIMONY OF
PHILIP J. NELSON
PUCO CASE NOS. 99-___-EL-ETP and
99-___-EL-ETP

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
PHILIP J. NELSON
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
CASE NO. 99-___-EL-ETP
AND
OHIO POWER COMPANY
CASE NO. 99-___-EL-ETP

Personal Data

Q. Please state your name and business address.

A. My name is Philip J. Nelson. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. Please indicate by whom you are employed and in what capacity.

A. I am employed as a Staff Financial Analyst in the Corporate Planning and Budgeting Department for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP) the parent of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCO).

Q. Please briefly describe your educational background and business experience.

A. I graduated from West Liberty State College in 1979 receiving a Bachelor of Science Degree, with highest honors, in Business Administration (Accounting Major). In 1979, I was employed by Wheeling Power Company, an affiliate of AEP, in the Managerial Department. At Wheeling Power, I was responsible for rate filings with the Public Service Commission of West Virginia (PSC), for resolving customer complaints made to the PSC, as well as for preparation of the Company's operating budgets and capital forecasts. In 1996 I transferred to AEP-

West Virginia State Office in Charleston, West Virginia as a senior rate analyst. In 1997 I transferred to AEPSC as a senior rate consultant in the Energy Pricing and Regulatory Services Department, with my primary responsibility being the oversight of OPCO's and CSP's EFC fuel filings. I was promoted to my current position on November 1, 1999.

Purpose of Testimony

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

A. The purpose of my testimony is to explain OPCO's deferred fuel cost regulatory asset associated with the Settlement Agreement in Case No. 94-996-EL-AIR, et al. (Settlement), and the component in the October 5, 1999 EFC rate that related to recovery of the deferred fuel cost regulatory asset. Specifically, I will be supporting the data provided in response to Part F, §B(1)(b)(iv) of the Commission's Rules for Electric Transition Plans. This rule deals with the Deferred Fuel Cost portion of regulatory assets included in a company's request for a transition charge. I am providing data in response to parts (a) and (b) of this rule for both OPCO and CSP.

List of Exhibits

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

EXHIBIT NO. ____ PJN-1 provides the projected net deferred fuel regulatory asset balance for OPCO as of December 31, 2000 calculated in accordance with the Settlement.

EXHIBIT NO. _____ PJN-2 provides a calculation of the component included in the October 5, 1999 EFC related to the recovery of the deferred fuel cost regulatory asset for OPCO.

EXHIBIT NO. _____PJN-3 provides the deferred fuel costs as of December 31, 1998 and the projections of same for December 31, 1999 and December 31, 2000 for CSP and OPCO.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Transition Charge for Deferred Fuel

Q. Please briefly describe the provisions of the Settlement that relate to the creation of the deferred fuel cost regulatory asset for OPCO at December 31, 2000?

A. There are several distinct pieces to the calculation of the deferred fuel cost regulatory asset under the provisions of the Settlement. Below I have paraphrased portions of the Settlement that deal with the EFC and the creation and recovery of the deferred fuel cost regulatory asset:

1. Operating Losses for the period June 1, 1995 through November 30, 1998 are the affiliate and non/affiliate coal costs, on an as burned basis, that would not be recoverable (and in fact were not recovered) under the fixed EFC rate of 1.465 cents/kWh. (See sections V.1.b and V.2 of the Settlement).

2. Operating Losses for the two-year period after November 30, 1998 are the difference between the actual cost of coal from the Muskingum and/or Windsor Mines, on an as burned basis, and the cost of comparable quality coal at market prices. (See sections V.1.b and V.5 of the Settlement).

3. Prior EFC Surplus is the net overrecovery of fuel costs through May 31, 1995 realized by OPCO under the Stipulation and Recommendation in Case No. 92-01-EL-EFC, which subsequently offset deferred operating losses accrued under the Stipulation. (See section V.12 of the Settlement).

4. Investment/Shutdown (I/S) Costs are the then remaining investment in each affiliate mining operation's assets plus all related shutdown liabilities. (See section V.1.e of the Settlement). The recovery of I/S costs of the Windsor and Muskingum Mines was limited to the "Ohio Proportional Jurisdictional Share" which was set at 43% for each of those mines. (See section V.1.c of the Settlement). The "Ohio Proportional Jurisdictional Share" of the Meigs Mine was to be determined in the manner specified in ¶ 3 of the Stipulation and Recommendation in Case No. 92-01-EL-EFC. (See section V.1.d of the Settlement). The "Ohio Proportional Jurisdictional Share" of the Meigs Mine is currently about 68%.

5. The Gavin Cap permits the Company to reprice Gavin plant's EFC includable fuel cost to the "Gavin Cap" price through 2009 to defer and recover its Operating Losses and I/S costs. An important component of the Gavin Cap was an escalation factor, which provided for inflationary

increases in the includable cost of fuel through 2009. The Gavin Cap, which was established in ¶ 2 of the Stipulation and Recommendation in Case No. 92-01-EL-EFC, was "available to recover first any Operating Losses deferred hereunder, then unrecovered fuel costs as provided for in ¶ 3 of the Stipulation and Recommendation approved by the Commission in Case No. 92-01-EL-EFC, and then the Ohio Proportional Jurisdictional Share of OPCO's Investment/Shutdown Costs associated with the Muskingum, Windsor and Meigs Mines in that order."

Q. How has Am. Sub. S. B. No. 3 affected the recovery of the operating losses and I/S costs?

A. As a result of Am. Sub. S. B. No. 3, beginning in 2001, EFC proceedings in Ohio cease, thus ending the recovery mechanism in the Settlement and specifically ceasing the escalation feature of the Gavin Cap. Therefore, OPCO must now rely on the transition charge for recovery of the deferred fuel cost regulatory asset balance after December 31, 2000. I explain the determination of the fuel component of the transition charge later in my testimony.

Calculation of Deferred Fuel Balances: Part F,§B(1)(b)(iv)(a)

Q. Has the Company calculated the December 31, 2000 estimated deferred fuel cost regulatory asset balance in accordance with the Settlement and the Commission's Transition Rules?

A. Yes. EXHIBIT NO. _____ PJN-1 provides the balance estimated for December 31, 2000 for OPCO.

Q. Please explain EXHIBIT NO. _____ PJN-1.

A. The format of the exhibit aligns with the various components of the Settlement. Item 1 shows the Operating Loss for the fixed rate period of June 1995 through November 1998. Item 2 shows the Operating Loss associated with the repricing of affiliate coal to market from December 1998 through November 2000. The third item is the amount of the prior EFC Surplus. Item 4 shows the calculation of the jurisdictional I/S costs. The fifth item is the amount of the deferred fuel cost recoveries provided by the Gavin Cap in accordance with the Settlement. The total deferred fuel cost regulatory asset balance at December 31, 2000 is the net of these five items.

Q. Have the affiliate mines been closed?

A. The Muskingum Mine which serves Muskingum River units 1 through 4, ceased operation in October, 1999 with the exception of a limited amount of economically viable coal production ancillary to the reclamation activities. Windsor Mine supplying Cardinal unit 1 is scheduled to close in April, 2000. Meigs Mine, which provides coal to Gavin, is tentatively scheduled to close in December, 2001, with accrual of the shutdown liabilities (excluding final reclamation and asset related accruals) being recorded in 2000 in accordance with Generally Accepted Accounting Principles (GAAP).

Q. Have any of the I/S costs been included in the price of the coal delivered to OPCO from its affiliate mines?

A. Yes. As permitted by the Settlement, OPCO records the liability for the shutdown of the affiliate mines upon the announcement of their closure and practices monthly sales price normalization for inclusion of shutdown costs in coal costs in advance of the actual shutdown dates. Also, as required by GAAP, the Company adjusts the recovery of its investment in mining assets to reflect their earlier shutdown dates, i.e. the reduction in economic life. The adjusted amortizations and depreciation provide for the spreading of the investment costs of the mine over the mine's remaining economic life. By adjusting amortizations and depreciation, the investment balances at the mines will be zero at the time each mine closes. As a result of these practices, most of the I/S costs will be billed to OPCO through the delivery of coal in advance of the shutdown date. Therefore, the total I/S costs shown reflect both costs that have been billed, as well as a lesser amount of I/S costs which have not yet been billed as of the end of 2000.

Q. If the closing date of Meigs mine changes from December 31, 2001, would the deferred fuel balance shown on EXHIBIT NO. ___ PJN-1 change?

A. Yes. Moving the closing date would affect the forecasted deferrals recorded in 2000 and therefore change the balance on this exhibit. The Company will provide a revised estimate in the event the closing date changes.

Unbundling of EFC Rate: Part F, §B(1)(b)(iv)(b)

Q. Is there a component of the October 5, 1999 EFC rate that related to recovery of the deferred fuel cost regulatory asset?

A. Yes. Pursuant to the Settlement, the effect of the Gavin Cap has been included in the EFC rates which were effective since December, 1998. The October 5, 1999 EFC rate reflected a base (forecast) period of December 1, 1998 through May 31, 1999. Therefore, the Fuel Component of the October 5, 1999 EFC rate reflects the effect of the Gavin Cap.

Q. What is the amount of the Gavin Cap recovery component in the EFC and how is it calculated?

A. The total EFC rate effective October 5, 1999 is 1.45654 cents per kWh. Of this rate, 0.11386 cents per kWh is a recovery under the Gavin Cap. This amount was derived by taking the difference between the Gavin fuel cost included in the base period at the Gavin Cap price, and the Gavin fuel cost that would have been included in the base period absent the Gavin Cap pricing and exclusive of any I/S costs. The difference was multiplied by the Ohio Proportional Jurisdictional Share for the Meigs Mine to arrive at a difference in EFC fuel cost. The difference in EFC fuel cost for the base period was then divided by the base period generation level kWh to arrive at the Gavin Cap recovery component of the EFC rate. EXHIBIT NO. _____ PJN-2 shows the calculation.

Additional Data Being Provided In Response To Part F, §B(1)(b)(iv)

Q. Have you prepared an exhibit which provides the deferred fuel cost balances as of December 31, 1998, 1999 and 2000 for CSP and OPCO?

A. Yes, EXHIBIT NO. ___ PJN-3 provides the requested information.

Q. Why are the December 31, 2000 over- and under-recovery balances projected to be $0?

A. Other than the balance created pursuant to the Settlement which I have previously discussed, the balance for normal deferred fuel, i.e. over- / under-recoveries, is projected to be $0 for CSP and OPCO. Since the Companies may have two more fuel filings prior to the start of the Market Development Period, the assumption is that the fuel proceedings would set the proper fuel rates in 2000 resulting in no over- or under-recovery balance at December 31, 2000.

Q. Please provide the reconciliation adjustment component of the electric fuel component (EFC), effective October 5, 1999, that compensates for over- and under-recoveries as required by the Commission's Transition Rules in Part F, §B(1)(b)(iv)(b).

A. The October 5, 1999 EFC rate for CSP contains a positive reconciliation adjustment (RA) of 0.03547 cents per kWh, of which the under-recovery component is 0.12901 cents per kWh. For OPCO the corresponding figures are a negative RA of (0.05136) which includes an over-recovery component of (0.00039) cents per kWh.

Q. Why is there a difference for each Company, between its total RA and the portion attributable to over- or under-recovery?

A. For CSP there are RA components related to emission allowances and the Ohio Coal Tax Credit which provide a credit to customers through the RA. For OPCO the other RA component relates to emission allowances. This component also provides additional credit through the RA.

Q. Does this conclude your testimony?

A. Yes it does.

OHIO POWER COMPANY
OPERATING LOSS AND INVESTMENT/SHUTDOWN COSTS
INCURRED THROUGH 12/31/00 ($000)
PUCO JURISDICTION

1. Operating Loss From 6/1/95 – 11/30/98 [Exclusive of Investment/Shutdown (I/S) Costs]	$32,468
2. Operating Loss From 12/01/98 - 11/30/00 [Exclusive of Investment/Shutdown (I/S) Costs]	$30,301
3. Prior EFC Surplus	($6,138)
Total Operating Loss Exclusive of Investment/Shutdown Costs	$56,631

4. Ohio Proportional Jurisdictional Share of Investment/Shutdown (I/S) Costs

Plant (Mine):	Total I/S Costs	Ohio Proport. Juris. Share	EFC Juris I/S Costs
Cardinal Unit 1 (Windsor)	$92,023	43%	$39,570
Muskingum River Units 1-4 (Muskingum)	$129,088	43%	$55,508
Gavin (Meigs)	$344,844	68%	$234,494
	$565,955		

Total Jurisdictional I/S Costs	$329,572*
Total Operating Loss and I/S Costs through 12/31/00	$386,203
5. Gavin Recoveries From 12/01/98 through 12/31/00	($26,478)
Net Deferred Fuel Cost Regulatory Asset as of 12/31/00	$359,725

* Does not include normal amortizations.

OHIO POWER COMPANY
CALCULATION OF GAVIN CAP RECOVERY COMPONENT
OF OCTOBER 5, 1999 EFC RATE

OCTOBER 5, 1999 EFC RATE CENTS/KWH 1.45654

GAVIN CAP INCLUDED IN 1.45654 MILLS/KWH RATE

	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Total
Capped Price (c/mBtu)	167.9	167.9	167.9	168.07	168.07	168.07	
Plant Consumption (tBtu)	16.8	16.9	15.2	16.9	16.3	15.9	
Capped Fuel Cost ($000)	$ 28,207	$ 28,375	$ 25,521	$ 28,404	$ 27,395	$ 26,723	$ 164,625

GAVIN COST W/O CAP AND EXCLUDING I/S COSTS

	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Total
Gavin Price (From Pool Report)	27,814	27,067	23,932	26,269	25,118	24,421	
Investment/Shutdown Included	1,948	2,153	1,884	2,274	2,403	2,588	
Net Gavin to Compare w/Capped Price	$ 25,866	$ 24,914	$ 22,048	$ 23,995	$ 22,715	$ 21,833	$ 141,371
Total Difference							$ 23,254
Gavin Jurisdiction Factor							0.68
EFC Jurisdictional Difference							$ 15,813
EFC Jurisdictional Sales							13,888,500

GAVIN CAP RECOVERY COMPONENT CENTS/KWH $\boxed{0.11386}$

RESIDUAL EFC FUEL RATE CENTS/KWH 1.34268

OPCO AND CSP
DEFERRED FUEL COST BALANCES ($000)
AS OF DECEMBER 31

	1998	1999		2000	
			a		a
OHIO POWER COMPANY					
Balances pursuant to Settlement Case No. 94-996-EL-AIR, et al.	105,957	194,414	b	359,725	
(Over)- Under-recovery Balances	(1,312)	(6,281)	c	0	
Total	104,645	188,133		359,725	
COLUMBUS SOUTHERN POWER CO.					
(Over)- Under-recovery Balances	13,375	1,138	c	0	

a: Projected
b: See workpaper
c: October 31 balances

Windsor Coal Company

Acclerated Amortizations & Post Shutdown Liabilities

	1995 Accrued Shutdown Costs	1996 Accrued Shutdown Costs	1997 Accrued Shutdown Costs	1998 Accrued Shutdown Costs	1999 Accrued Shutdown Costs (JAN TO JUL)	1999 Projected Shutdown Costs (AUG TO DEC)	2000 Projected Shutdown Costs	Remaining Unbooked Liability	Salvage/ Other Adjustments	Net Adjusted Accel Amort & Post Shutdown Liability
Accelerated Amortizations										
Mineral (Depletion)	195	350	206	211	116	148	119			$ 1,345
Development	560	1,021	630	743	423	460	720			$ 4,557
Depreciable Assets	319	1,986	2,121	1,844	1,541	1,284	1,026			$ 10,121
Leased Assets	1,404	455	511	522	131					$ 3,023
Deferred Royalties	863	1,676	985	1,625	798	1,167	1,223			$ 8,237
Related Tax Effect:										
- Development	45	13	8	9	5	6	9			$ 95
- Owned Assets	(34)	(214)	(226)	(199)	(166)	(138)	(110)			$ (1,089)
Subtotal	3,352	5,287	4,233	4,655	2,848	2,927	2,987	$ -	$ -	$ 26,289
Post Shutdown Liabilities										
Land								$ 633	$ (633)	$ -
M&S Inventory					3,588			$ 189	$ (189)	$ 3,588
Prepetual Water Treatment					8,706					$ 8,706
Final Reclamation		1,343	2,600	3,195	1,946	3,887	3,140			$ 16,111
UMW Layoff					1,027					$ 1,027
UMW OPEB					13,760			$ 232		$ 13,992
Pension Withdrawal					-					$ -
Rockefeller Bill					2,122					$ 2,122
COLI										$ -
Non-UMWA Layoff					5,231					$ 5,231
Non-UMWA Liabilities					-			$ 1,021		$ 1,021
Workers Compensation					13,936					$ 13,936
Subtotal Post Shutdown	-	1,343	2,600	3,195	50,316	3,887	3,140	$ 2,075	$ (822)	$ 65,734
Total Shutdown Expenses	3,352	6,630	6,833	7,850	53,164	6,814	6,127	$ 2,075	$ (822)	$ 92,023
Total through 12/99						84,643				

Central Ohio Coal Company
Acclerated Amortizations & Post Shutdown Liabilities

	1995 Accrued Shutdown Costs	1996 Accrued Shutdown Costs	1997 Accrued Shutdown Costs	1998 Accrued Shutdown Costs	1999 Accrued Shutdown Costs (JAN TO JUL)	1999 Projected Shutdown Costs (AUG TO DEC)	2000 Projected Shutdown Costs	Remaining Unbooked Liability	Salvage/ Other Adjustments	Net Adjusted Accel Amort & Post Shutdown Liability
Accelerated Amortizations										
Mineral (Depletion)	1,451	2,926	1,848	1,572	840	417				$ 9,054
Development										
Depreciable Assets	81	125	126	391	2,114	1,399		$ 311	$ (311)	$ 4,236
Leased Assets	2,999	4,737	4,677	8,985	2,596					$ 23,994
Gain on 2570 Dragline	(626)	(1,032)	(991)	(991)	(248)					$ (3,888)
Related Tax Effect:										
- Depletion	377	791	481	409	219	108				$ 2,385
- Dragline	57	96	92	92	23					$ 360
Subtotal	4,339	7,843	6,233	10,458	5,544	1,924	-	$ 311	$ (311)	$ 36,141
Post Shutdown Liabilities										
Land								$ 324	$ (324)	$ -
M&S Inventory				4,649		(10)		$ 1,419	$ (1,419)	$ 4,639
Prepetual Water Treatment				4,840	1,810	(2,703)				$ 3,947
Final Reclamation		7,323	13,338	10,698	6,997	3,026				$ 41,382
UMW Layoff				448		144				$ 592
UMW OPEB				24,083	6,333	(1,064)				$ 29,352
Pension Withdrawal										$ -
Rockefeller Bill				640		108				$ 748
COLI								$ 10,211	$ (10,211)	$ -
Non-UMWA Layoff				3,645		5				$ 3,650
Non-UMWA Liabilities						-		$ 2,288		$ 2,288
Workers Compensation				6,327		22				$ 6,349
Subtotal Post Shutdown	-	7,323	13,338	55,330	15,140	(472)	-	$ 14,242	$ (11,954)	$ 92,947
Total Shutdown Expenses	4,339	14,968	19,571	65,788	20,684	1,452	-	$ 14,553	$ (12,265)	$ 129,088
Total through 12/99						126,800				

Southern Ohio Coal Company
Acclerated Amortizations & Post Shutdown Liabilities

	1995 Accrued Shutdown Costs	1996 Accrued Shutdown Costs	1997 Accrued Shutdown Costs	1998 Accrued Shutdown Costs	1999 Accrued Shutdown Costs (JAN TO JUL)	1999 Projected Shutdown Costs (AUG TO DEC)	2000 Projected Shutdown Costs	Remaining Unbooked Liability	Salvage/ Other Adjustments	Net Adjusted Accel Amort & Post Shutdown Liability
Accelerated Amortizations										
Mineral (Depletion)	112	327	759	685	419	409	982	$ 941		$ 4,633
Development	1,404	4,049	10,049	9,193	5,621	5,469	13,127	$ 13,127		$ 62,039
Depreciable Assets		217	1,302	1,264	714	510	1,224	$ 1,223		$ 6,455
Leased Assets		20	928	920	538	383	919	$ 919		$ 4,627
Related Tax Effect:										
- Development	756	2,180	5,411	4,950	3,027	2,945	7,068	$ 7,068		$ 33,405
Subtotal	2,272	6,793	18,449	17,012	10,319	9,717	23,320 #	23,278 #	- #	111,159
Post Shutdown Liabilities										
Land								$ 7,629	$ (7,629)	$ -
M&S Inventory							7,963	$ 1,991	$ (1,991)	$ 7,963
Prepetual Water Treatment							8,628			$ 8,628
Final Reclamation		2,835	8,245	6,756	4,026	5,064	11,753	$ 11,742		$ 50,421
UMW Layoff							4,855			$ 4,855
UMW OPEB							54,964	$ 23,231		$ 78,195
Pension Withdrawal							26,085			$ 26,085
Rockefeller Bill							765			$ 765
COLI								$ 18,434	$ (18,434)	$ -
Non-UMWA Layoff							21,263			$ 21,263
Non-UMWA Liabilities							-	$ 4,800		$ 4,800
Workers Compensation							30,709	$ -		$ 30,709
Subtotal Post Shutdown	-	2,835	8,245	6,756	4,026	5,064	166,985	$ 67,827	$ (28,054)	$ 233,684
Total Shutdown Expenses	2,272	9,628	26,694	23,768	14,345	14,781	190,305	$ 91,105	$ (28,054)	$ 344,844
Total through 12/99						91,488				

AEP Fuel Supply - Affiliated Mines
Acclerated Amortizations & Post Shutdown Liabilities

	1995 Accrued Shutdown Costs	1996 Accrued Shutdown Costs	1997 Accrued Shutdown Costs	1998 Accrued Shutdown Costs	1999 Accrued Shutdown Costs (JAN TO JUL)	1999 Projected Shutdown Costs (AUG TO DEC)	2000 Projected Shutdown Costs	Remaining Unbooked Liability	Salvage/ Other Adjustments	Net Adjusted Accel Amort & Post Shutdown Liability
Accelerated Amortizations										
Mineral (Depletion)	1,758	3,603	2,813	2,468	1,375	974	1,101	$ 941		$ 15,032
Development	1,964	5,070	10,679	9,936	6,044	5,929	13,847	$ 13,127		$ 66,596
Depreciable Assets	400	2,328	3,549	3,499	4,389	3,194	2,250	$ 1,534	$ (311)	$ 20,812
Leased Assets	4,403	5,212	6,116	10,427	3,265	383	919	$ 919		$ 31,644
Gain on 2570 Dragline	(626)	(1,032)	(991)	(991)	(248)	-	-	$ -		$ (3,888)
Deferred Royalties	863	1,676	985	1,525	798	1,167	1,223	$ -		$ 8,237
Related Tax Effect	1,201	2,866	5,764	5,261	3,108	2,921	6,967	7,068		$ 35,156
Subtotal	9,963	19,723	28,915	32,125	18,711	14,568	26,307	$ 23,589	$ (311)	$ 173,589
Post Shutdown Liabilities										
Land	-	-	-	-	-	-	-	$ 8,586	$ (8,586)	$ -
M&S Inventory	-	-	-	4,649	3,588	(10)	7,963	$ 3,599	$ (3,599)	$ 16,190
Prepetual Water Treatment	-	-	-	4,840	10,516	(2,703)	8,628	$ -	$ -	$ 21,281
Final Reclamation	-	11,501	24,183	20,649	12,969	11,977	14,893	$ 11,742	$ -	$ 107,914
UMW Layoff	-	-	-	448	1,027	144	4,855	$ -	$ -	$ 6,474
UMW OPEB	-	-	-	24,083	20,093	(1,064)	54,964	$ 23,463	$ -	$ 121,539
Pension Withdrawal	-	-	-	-	-	-	26,085	$ -	$ -	$ 26,085
Rockefeller Bill	-	-	-	640	2,122	108	765	$ -	$ -	$ 3,635
COLI	-	-	-	-	-	-	-	$ 28,645	$ (28,645)	$ -
Non-UMWA Layoff	-	-	-	3,645	5,231	5	21,263	$ -	$ -	$ 30,144
Non-UMWA Liabilities	-	-	-	-	-	-	-	$ 8,109	$ -	$ 8,109
Workers Compensation	-	-	-	6,327	13,936	22	30,709	$ -	$ -	$ 50,994
Subtotal Post Shutdown	-	11,501	24,183	65,281	69,482	8,479	170,125	$ 84,144	$ (40,830)	$ 392,365
Total Shutdown Expenses	9,963	31,224	53,098	97,406	88,193	23,047	196,431	$ 107,733	$ (41,141)	$ 565,954

Total through 12/99 302,931

OHIO POWER COMPANY
OPERATING LOSS ESTIMATE FROM 12/98 THROUGH 11/00
GAVIN RECOVERIES THROUGH 12/00

Operating Loss Excl. I/S:

	Total O.L.	I/S	Total O.L. Excl. I/S
Dec-98	$6,301,953	$3,477,574	$2,824,379
Jan-99	$5,965,495	$4,767,295	$1,198,200
Feb-99	$3,226,540	$4,345,887	($1,119,347)
Mar-99	$2,942,445	$3,741,362	($798,917)
Apr-99	$2,800,605	$3,163,330	($362,725)
May-99	$4,179,009	$4,992,623	($813,614)
Jun-99	$8,714,901	$5,636,884	$3,078,017
Jul-99	$9,598,602	$5,737,601	$3,861,001
Aug-99	$7,947,713	$5,450,016	$2,497,697
Subtotal	$51,677,263	$41,312,572	$10,364,691
Gavin Recoveries included above			$4,562,881
Operating Loss Excluding I/S and Gavin Recoveries			$14,927,572
Forecast			
Sep-99			$1,934,000
Oct-99			$1,268,100
Nov-99			$1,259,100
Dec-99			$968,600
Subtotal O.L. from 12/98 - 12/99			$20,357,372
Jan-00			$1,273,200
Feb-00			$1,314,300
Mar-00			$1,796,400
Apr-00			$1,882,600
May-00			$1,632,400
Jun-00			$847,300
Jul-00			$473,100
Aug-00			$308,500
Sep-00			$201,800
Oct-00			$131,200
Nov-00			$82,500
Subtotal O.L. from 12/98 - 11/00			$30,300,672

Gavin Recoveries:

12/98 through 8/99	$4,562,881
Sep-99	($253,700)
Oct-99	$279,800
Nov-99	$254,200
Dec-99	$561,400
Subtotal Gavin Recoveries through 12/99	$5,404,581
Jan-00	$1,050,500
Feb-00	$1,271,200
Mar-00	$1,692,900
Apr-00	$1,266,300
May-00	$1,902,600
Jun-00	$1,832,800
Jul-00	$1,807,200
Aug-00	$1,907,200
Sep-00	$2,097,600
Oct-00	$2,031,400
Nov-00	$2,040,500
Dec-00	$2,173,000
Subtotal Gavin Recoveries through 12/00	$26,477,781

OHIO POWER COMPANY
CALCULATION OF EFC SURPLUS AND OPERATING LOSS
EXCLUSIVE OF I/S COSTS THROUGH 8/99

<u>PRIOR EFC SURPLUS</u>

Final Results for Period Ending 11/30/94	$	(11,980,171)
Final Results for Period From 12/01/94 to 5/31/95	$	5,842,483
Net Prior EFC Surplus	$	(6,137,688)

<u>OPERATING LOSS FIXED RATE PERIOD: 6/01/95 TO 11/30/98</u>

Total	$	107,644,427
Investment/Shutdown Costs included	$	75,177,217
Operating Loss Exclusive of I/S Costs	$	32,467,210

<u>OPERATING LOSS FROM 12/01/98 THROUGH 8/31/99</u>

Total	$	51,677,263
Investment/Shutdown Costs included	$	41,312,572
Operating Loss Exclusive of I/S Costs	$	10,364,691

OHIO POWER COMPANY
JURISDICTIONAL FUEL EXPENSE vs FUEL RECOVERIES
FOR THE PERIOD FROM 06/01/95 to 11/30/98

MONTH	ACTUAL COST IN DOLLARS	RECOVERIES IN DOLLARS	SYS LOSS GAIN/(LOSS)	REPRICING GAIN/(LOSS)	CUMULATIVE REPRICING GAIN/(LOSS)
06/95	30,792,643	27,350,243	(14,695)	(3,457,095)	(3,457,095)
07/95	32,825,403	27,722,548	(95,974)	(5,198,829)	(8,655,924)
08/95	36,652,146	31,909,837	(364,444)	(5,106,753)	(13,762,677)
09/95	28,318,985	28,572,273	(78,771)	174,517	(13,588,160)
10/95	28,632,364	26,617,375	51,878	(1,963,111)	(15,551,271)
11/95	29,599,983	27,125,176	24,284	(2,450,523)	(18,001,794)
12/95	32,569,921	30,121,638	(109,655)	(2,557,938)	(20,559,732)
01/96	33,953,385	34,788,452	37,403	872,470	(19,687,262)
02/96	31,402,894	31,776,329	85,598	459,033	(19,228,229)
03/96	30,194,647	30,058,668	76,596	(59,383)	(19,287,612)
04/96	27,241,222	29,336,890	300,994	2,396,662	(16,890,950)
05/96	28,960,795	28,181,064	123,584	(656,147)	(17,547,097)
06/96	29,216,273	27,027,790	32,113	(2,156,370)	(19,703,467)
07/96	31,359,856	30,455,455	170,158	(734,243)	(20,437,710)
08/96	31,347,434	29,471,655	223,360	(1,652,419)	(22,090,129)
09/96	30,563,680	29,085,674	(86,445)	(1,564,451)	(23,654,580)
10/96	32,185,448	27,467,276	(160,025)	(4,878,197)	(28,532,777)
11/96	29,986,218	25,734,336	(53,923)	(4,305,805)	(32,838,582)
12/96	33,089,954	30,912,531	0	(2,177,423)	(35,016,005)
01/97	35,552,590	32,783,665	0	(2,768,925)	(37,784,930)
02/97	29,609,361	29,704,068	0	94,707	(37,690,223)
03/97	31,115,548	28,748,584	0	(2,366,964)	(40,057,187)
04/97	29,318,974	28,838,378	0	(480,596)	(40,537,783)
05/97	29,215,892	26,332,675	0	(2,883,217)	(43,421,000)
06/97	29,739,062	26,879,097	0	(2,859,965)	(46,280,965)
07/97	32,227,115	29,798,112	0	(2,429,003)	(48,709,968)
08/97	31,967,588	28,873,727	0	(3,093,861)	(51,803,829)
09/97	30,773,239	29,092,602	0	(1,680,637)	(53,484,466)
10/97	33,353,153	28,205,733	0	(5,147,420)	(58,631,886)
11/97	32,143,711	26,128,405	0	(6,015,306)	(64,647,192)
12/97	36,088,359	33,521,336	0	(2,567,023)	(67,214,215)
01/98	35,270,404	32,427,773	0	(2,842,631)	(70,056,846)
02/98	32,349,340	29,003,006	0	(3,346,334)	(73,403,180)
03/98	36,121,136	31,736,657	0	(4,384,479)	(77,787,659)
04/98	30,928,703	29,286,967	0	(1,641,736)	(79,429,395)
05/98	34,819,311	27,615,349	0	(7,203,962)	(86,633,357)
06/98	31,830,402	29,631,006	0	(2,199,396)	(88,832,753)
07/98	35,909,339	29,416,322	0	(6,493,017)	(95,325,770)
08/98	33,152,498	29,675,694	(136,333)	(3,613,137)	(98,938,907)
09/98	33,577,486	32,202,266	0	(1,375,220)	(100,314,127)
10/98	27,762,864	28,432,350	0	669,486	(99,644,641)
11/98	32,907,347	27,612,332	(1,196,929)	(6,491,944)	(106,136,585)
	1,334,626,673	1,229,661,314	(1,171,226)	(106,136,585)	
Adjustment for PUCO 5/26/99 Order - Emission Allowance Exp.				(1,507,842)	
Total				(107,644,427)	

OHIO POWER COMPANY
SUMMARY OF REPRICING PER SETTLEMENT IN CASE NO. 94-996-EL-AIR
GAVIN REPRICED AT 157.5 CENTS/mmBtu AS ECALATED
MARKET PRICE AT CARDINAL UNIT 1 AND MUSKINGUM UNITS 1 - 4

FOR THE PERIOD BEGINNING 12/01/98
Summary of Cumulative Recovery

MONTH		ACTUAL COST IN DOLLARS	REPRICED COST IN DOLLARS	REPRICING GAIN/(LOSS)	CUMULATIVE REPRICING GAIN/(LOSS)
Dec-98		$38,791,193	$32,489,240	($6,301,953)	($6,301,953)
Jan-99		$41,362,953	$35,397,458	($5,965,495)	($12,267,448)
Feb-99		$33,674,491	$30,447,951	($3,226,540)	($15,493,988)
Mar-99		$37,091,426	$34,148,981	($2,942,445)	($18,436,433)
Apr-99		$31,833,020	$29,032,415	($2,800,605)	($21,237,038)
May-99		$34,315,963	$30,136,954	($4,179,009)	($25,416,047)
Jun-99		$42,548,648	$33,833,747	($8,714,901)	($34,130,948)
Jul-99		$53,645,285	$44,046,683	($9,598,602)	($43,729,550)
Aug-99	E	$43,883,814	$35,936,101	($7,947,713)	($51,677,263)
		$357,146,793	$305,469,530	($51,677,263)	

E=Estimated

Ohio Power Company
Jurisdictional Portion of Investment (Accelerated Depreciation)/ Shutdown Costs
Included in Deferred Fuel From 6/01/95

	Cardinal Unit 1			Muskingum Units 1 - 4			Gavin			Total
DATE	Cons $	Juris %	Juris $	Cons $	Juris %	Juris $	Cons $	Juris %	Juris $	Juris $
07/95	E $ 475,507	70.72%	$ 336,279	E $ 62,998	18.02%	$ 11,352	$ 145,396	61.37%	$ 89,230	$ 436,861
08/95	E $ 541,650	70.72%	$ 383,055	E $ 207,598	18.02%	$ 37,409	$ 207,482	63.59%	$ 131,938	$ 552,402
09/95	E $ 499,396	70.72%	$ 353,173	E $ 248,616	18.02%	$ 44,801	$ 251,103	59.34%	$ 149,005	$ 546,979
10/95	$ 488,000	71.44%	$ 348,627	$ 271,621	0.00%	$ -	$ 276,844	71.89%	$ 199,023	$ 547,650
11/95	$ 397,332	74.10%	$ 294,423	$ 382,261	10.01%	$ 38,264	$ 334,727	74.09%	$ 247,999	$ 580,686
12/95	$ 382,435	67.05%	$ 256,423	$ 391,763	34.42%	$ 134,845	$ 351,882	68.51%	$ 241,074	$ 632,342
01/96	$ 668,830	73.15%	$ 489,249	$ 420,095	39.86%	$ 167,450	$ 431,759	74.37%	$ 321,099	$ 977,798
02/96	$ 555,178	66.36%	$ 368,416	$ 477,834	39.01%	$ 186,403	$ 524,114	67.15%	$ 351,943	$ 906,762
03/96	$ 405,202	63.92%	$ 259,005	$ 695,890	28.08%	$ 195,406	$ 535,106	63.98%	$ 342,362	$ 796,773
04/96	$ 423,490	66.75%	$ 282,680	$ 904,384	15.47%	$ 139,908	$ 320,724	68.40%	$ 219,375	$ 641,963
05/96	$ 777,926	76.79%	$ 597,369	$ 998,843	14.37%	$ 143,534	$ 258,487	79.76%	$ 206,169	$ 947,072
06/96	$ 486,565	80.84%	$ 393,339	$ 584,292	16.95%	$ 99,037	$ 375,754	81.30%	$ 305,488	$ 797,864
07/96	$ 376,198	70.08%	$ 263,640	$ 775,709	7.85%	$ 60,893	$ 817,417	70.62%	$ 577,280	$ 901,793
08/96	$ 665,629	62.60%	$ 416,684	$ 1,019,411	6.38%	$ 65,038	$ 944,040	66.75%	$ 630,147	$ 1,111,869
09/96	$ 606,757	72.01%	$ 436,926	$ 1,155,270	16.53%	$ 190,966	$ 1,022,004	72.44%	$ 740,340	$ 1,368,232
10/96	$ 587,993	77.36%	$ 454,989	$ 1,827,111	14.57%	$ 266,210	$ 854,066	77.97%	$ 665,915	$ 1,387,114
11/96	$ 51,136	74.04%	$ 37,863	$ 1,905,232	3.62%	$ 68,969	$ 1,335,640	74.04%	$ 988,908	$ 1,095,740
12/96	$ 204,619	68.36%	$ 139,878	$ 2,304,568	9.22%	$ 212,481	$ 1,378,568	68.98%	$ 950,936	$ 1,303,295
01/97	$ 886,438	69.77%	$ 618,468	$ 2,458,126	8.84%	$ 217,298	$ 1,811,988	72.46%	$ 1,312,967	$ 2,148,733
02/97	$ 659,514	75.15%	$ 495,625	$ 1,686,005	5.53%	$ 93,238	$ 1,671,966	76.94%	$ 1,286,411	$ 1,875,272
03/97	$ 326,576	69.29%	$ 226,285	$ 1,953,323	4.03%	$ 78,719	$ 1,895,999	74.54%	$ 1,413,278	$ 1,718,282
04/97	$ 686,585	64.05%	$ 439,758	$ 2,013,699	6.55%	$ 131,897	$ 1,811,705	68.50%	$ 1,241,018	$ 1,812,673
05/97	$ 732,666	70.01%	$ 512,939	$ 2,663,273	10.13%	$ 269,790	$ 1,909,955	72.48%	$ 1,384,335	$ 2,167,064
06/97	$ 348,088	75.26%	$ 261,971	$ 2,073,884	12.07%	$ 250,318	$ 1,800,073	79.56%	$ 1,432,138	$ 1,944,427
07/97	$ 521,420	79.80%	$ 416,093	$ 1,695,204	48.28%	$ 818,444	$ 1,402,702	84.76%	$ 1,188,930	$ 2,423,467
08/97	$ 842,811	82.63%	$ 696,415	$ 1,251,648	47.32%	$ 592,280	$ 1,315,633	85.69%	$ 1,127,366	$ 2,416,061
09/97	$ 1,120,338	61.90%	$ 693,489	$ 1,265,402	38.57%	$ 488,066	$ 2,004,645	67.18%	$ 1,346,721	$ 2,528,276
10/97	$ 882,352	58.34%	$ 514,764	$ 1,182,995	34.40%	$ 406,950	$ 2,507,067	65.59%	$ 1,644,398	$ 2,566,112
11/97	$ 426,502	62.66%	$ 267,246	$ 1,538,831	38.27%	$ 588,911	$ 2,424,210	68.30%	$ 1,655,735	$ 2,511,892
12/97	$ 384,588	63.18%	$ 242,983	$ 2,135,233	44.40%	$ 948,043	$ 2,536,006	67.03%	$ 1,699,886	$ 2,890,912
01/98	$ 593,139	61.31%	$ 363,654	$ 3,098,422 S	38.91%	$ 1,205,596	$ 3,212,619	62.71%	$ 2,014,633	$ 3,583,883
02/98	$ 434,685	64.86%	$ 281,937	$ 4,034,512 S	39.31%	$ 1,585,967	$ 2,952,350	65.05%	$ 1,920,504	$ 3,788,408
03/98	$ 425,392	61.36%	$ 261,021	$ 5,351,293 S	39.89%	$ 2,134,631	$ 3,074,614	62.01%	$ 1,906,568	$ 4,302,220
04/98	$ 512,237	60.97%	$ 312,311	$ 6,011,128 S	15.18%	$ 912,489	$ 2,296,366	64.47%	$ 1,480,467	$ 2,705,267
05/98	$ 574,158	56.14%	$ 322,332	$ 7,431,550 S	15.88%	$ 1,180,130	$ 2,590,162	61.57%	$ 1,594,763	$ 3,097,225
06/98	$ 654,048	61.81%	$ 404,267	$ 6,697,806 S	23.02%	$ 1,541,835	$ 2,091,974	68.19%	$ 1,426,517	$ 3,372,619
07/98	$ 816,110	53.78%	$ 439,980	$ 5,079,262 S	24.72%	$ 1,255,594	$ 2,361,841	63.73%	$ 1,505,201	$ 3,200,775
08/98	$ 634,018	54.90%	$ 348,076	$ 5,987,973 S	15.68%	$ 938,914	$ 2,428,562	64.86%	$ 1,575,165	$ 2,862,155
09/98	$ 510,161	68.34%	$ 348,658	$ 4,359,960 S	21.47%	$ 936,088	$ 1,317,172	75.34%	$ 992,357	$ 2,277,103
10/98	$ -	0.00%	$ -	$ 3,308,898 S	15.51%	$ 513,210	$ 775,710	72.54%	$ 562,700	$ 1,075,910
11/98	$ 835,172	45.69%	$ 381,590	$ 4,843,280 S	18.50%	$ 896,007	$ 1,666,447	65.87%	$ 1,097,689	$ 2,375,286
Subtotal	$ 22,402,863		$14,961,860	$ 92,755,223		$20,047,379	$58,224,903		$40,167,958	$ 75,177,217
12/98	$ 736,648	68.83%	$ 507,035	$ 3,697,930	44.23%	$ 1,635,594	$ 1,947,972	68.53%	$ 1,334,945	$ 3,477,574
01/99	$ 2,749,675 S	65.84%	$ 1,810,366	$ 4,127,322	37.84%	$ 1,561,779	$ 2,153,311	64.79%	$ 1,395,130	$ 4,767,295
02/99	$ 2,560,374 S	65.95%	$ 1,688,567	$ 3,763,884 S	38.40%	$ 1,445,331	$ 1,884,311	64.32%	$ 1,211,989	$ 4,345,887
03/99	$ 3,621,196 S	58.09%	$ 2,103,553	$ 1,208,038 S	25.66%	$ 309,983	$ 2,278,747	58.27%	$ 1,327,826	$ 3,741,362
04/99	$ 2,580,226 S	63.59%	$ 1,640,766	$ 668,068	5.56%	$ 37,145	$ 2,403,201	61.81%	$ 1,485,419	$ 3,163,330
05/99	$ 3,559,466 S	62.86%	$ 2,237,480	$ 3,729,848	32.26%	$ 1,203,995	$ 2,588,267	59.93%	$ 1,551,148	$ 4,992,623
06/99	$ 4,209,025 S	78.04%	$ 3,284,723	$ 3,418,187	41.73%	$ 1,426,409	$ 1,230,399	75.24%	$ 925,752	$ 5,636,884
07/99	$ 4,990,295 S	70.34%	$ 3,510,174	$ 2,423,870	40.83%	$ 989,666	$ 1,739,650	71.15%	$ 1,237,761	$ 5,737,601
08/99	E $ 5,115,336 S	70.34%	$ 3,598,127	E $ 1,868,524	40.83%	$ 762,918	E $ 1,530,528	71.15%	$ 1,088,971	$ 5,450,016
Subtotal	$ 30,122,241		$20,380,811	$ 24,905,671		$ 9,372,820	$17,756,386		$11,558,941	$ 41,312,572
	-		-	-		-	-		-	-
Total	$ 52,525,104		$35,342,691	$117,660,894		$29,420,199	$75,981,289		$51,726,899	$116,489,789

E = ESTIMATED JURISDICTIONAL %
S = SHUT DOWN COSTS INCLUDED

GAVIN JURISDICTIONAL CALCULATION
PER SETTLEMENT IN CASE NO. 94-996-EL-AIR

MONTH/ YEAR	(1) NET GENERATION MWH	(2) GENERATION ASSIGNED TO SYS SALES MWH	(3) GENERATION REMAINING ON SYSTEM (1)-(2) MWH	(4) PUCO SYSTEM RATIO	(5) GENERATION ASSIGNED TO PUCO JURIS (3)X(4) MWH	(6) PUCO JURISDICTIONAL SHARE (5)/(1)
Dec-91	1,489,806	178,135	1,311,671	0.641248	841,106	0.5646
Jan-92	1,487,928	111,387	1,376,541	0.630882	868,435	0.5837
Feb-92	1,484,264	89,119	1,395,145	0.673664	939,859	0.6332
Mar-92	958,110	25,388	932,722	0.665821	621,026	0.6482
Apr-92	829,114	5,313	823,801	0.718609	591,991	0.7140
May-92	782,131	18,287	763,844	0.70005	534,729	0.6837
Jun-92	1,325,957	9,889	1,316,068	0.607654	799,714	0.6031
Jul-92	1,469,952	54,989	1,414,963	0.575483	814,287	0.5540
Aug-92	1,441,098	13,714	1,427,384	0.573181	818,149	0.5677
Sep-92	1,474,919	4,042	1,470,877	0.551154	810,680	0.5496
Oct-92	1,630,837	33,142	1,597,695	0.618408	988,027	0.6058
Nov-92	807,611	29,452	778,159	0.775185	603,217	0.7469
Dec-92	807,392	4,950	802,442	0.752575	603,898	0.7480
Jan-93	1,076,293	33,349	1,042,944	0.762358	795,097	0.7387
Feb-93	1,341,701	67,748	1,273,953	0.680132	866,456	0.6458
Mar-93	1,347,229	87,693	1,259,536	0.689992	869,070	0.6451
Apr-93	1,296,323	108,770	1,187,553	0.673768	800,135	0.6172
May-93	1,366,266	88,423	1,277,843	0.654739	836,654	0.6124
Jun-93	1,161,006	13,557	1,147,449	0.666558	764,841	0.6588
Jul-93	1,489,989	132,839	1,357,150	0.65013	882,324	0.5922
Aug-93	1,523,454	75,911	1,447,543	0.677604	980,861	0.6438
Sep-93	1,187,966	47,040	1,140,926	0.717742	818,891	0.6893
Oct-93	831,767	56,847	774,920	0.854207	661,942	0.7958
Nov-93	725,756	37,797	687,959	0.865756	595,605	0.8207
Dec-93	563,285	40,636	522,649	0.863805	451,467	0.8015
Jan-94	1,265,076	128,736	1,136,340	0.711497	808,503	0.6391
Feb-94	1,543,277	105,970	1,437,307	0.673965	968,695	0.6277
Mar-94	1,678,044	51,667	1,626,377	0.616278	1,002,300	0.5973
Apr-94	895,952	21,089	874,863	0.777385	680,105	0.7591
May-94	828,391	6,536	821,855	0.799472	657,050	0.7932
Jun-94	782,722	23,522	759,200	0.802031	608,902	0.7779
Jul-94	1,100,622	84,013	1,016,609	0.744472	756,837	0.6876
Aug-94	1,148,614	100,091	1,048,523	0.806536	845,672	0.7363
Sep-94	1,160,423	84,521	1,075,902	0.715176	769,459	0.6631
Oct-94	777,842	46,121	731,721	0.685162	501,347	0.6445
Nov-94	706,461	30,374	676,087	0.778814	526,546	0.7453
Dec-94	588,965	14,488	574,477	0.785923	451,495	0.7666
Jan-95	68,621	0	68,621	0.893543	61,316	0.8935
Feb-95	652,259	48,961	603,298	0.881111	531,573	0.8150
Mar-95	992,515	72,442	920,073	0.856012	787,594	0.7935

GAVIN JURISDICTIONAL CALCULATION
PER SETTLEMENT IN CASE NO. 94-996-EL-AIR

MONTH/ YEAR	(1) NET GENERATION MWH	(2) GENERATION ASSIGNED TO SYS SALES MWH	(3) GENERATION REMAINING ON SYSTEM (1)-(2) MWH	(4) PUCO SYSTEM RATIO	(5) GENERATION ASSIGNED TO PUCO JURIS (3)X(4) MWH	(6) PUCO JURISDICTIONAL SHARE (5)/(1)
Apr-95	1,196,887	112,390	1,084,497	0.818919	888,115	0.7420
May-95	1,420,167	93,436	1,326,731	0.769244	1,020,580	0.7186
Jun-95	1,184,943	94,154	1,090,789	0.757551	826,328	0.6974
Jul-95	1,418,073	77,180	1,340,893	0.649054	870,312	0.6137
Aug-95	1,643,009	50,679	1,592,330	0.656089	1,044,710	0.6359
Sep-95	1,515,576	55,628	1,459,948	0.616061	899,417	0.5934
Oct-95	1,270,631	125	1,270,506	0.718929	913,404	0.7189
Nov-95	1,397,357	2,456	1,394,901	0.742179	1,035,266	0.7409
Dec-95	1,375,831	38,339	1,337,492	0.70472	942,557	0.6851
Jan-96	1,418,046	0	1,418,046	0.743716	1,054,623	0.7437
Feb-96	1,640,218	11	1,640,207	0.671546	1,101,474	0.6715
Mar-96	1,581,839	344	1,581,495	0.639902	1,012,002	0.6398
Apr-96	995,266	298	994,968	0.6842	680,757	0.6840
May-96	752,143	7	752,136	0.79764	599,934	0.7976
Jun-96	1,053,877	248	1,053,629	0.81318	856,790	0.8130
Jul-96	1,535,733	324	1,535,409	0.706303	1,084,464	0.7062
Aug-96	1,733,985	203	1,733,782	0.667601	1,157,475	0.6675
Sep-96	1,604,809	248	1,604,561	0.724492	1,162,492	0.7244
Oct-96	1,209,714	1,280	1,208,434	0.780509	943,194	0.7797
Nov-96	1,719,181	0	1,719,181	0.740369	1,272,828	0.7404
Dec-96	1,643,199	2	1,643,197	0.689794	1,133,467	0.6898
Jan-97	1,399,775	76	1,399,699	0.724665	1,014,313	0.7246
Feb-97	1,117,389	27	1,117,362	0.769403	859,702	0.7694
Mar-97	1,304,510	4	1,304,506	0.745394	972,371	0.7454
Apr-97	1,244,117	0	1,244,117	0.684953	852,162	0.6850
May-97	1,269,588	0	1,269,588	0.724844	920,253	0.7248
Jun-97	1,213,284	29	1,213,255	0.795668	965,348	0.7956
Jul-97	917,251	0	917,251	0.847594	777,456	0.8476
Aug-97	847,523	0	847,523	0.856875	726,221	0.8569
Sep-97	1,261,734	0	1,261,734	0.671756	847,577	0.6718
Oct-97	1,507,091	0	1,507,091	0.655859	988,439	0.6559
Nov-97	1,455,283	0	1,455,283	0.682966	993,909	0.6830
Dec-97	1,467,902	0	1,467,902	0.670349	984,007	0.6703
Jan-98	1,776,902	0	1,776,902	0.627105	1,114,304	0.6271
Feb-98	1,665,288	0	1,665,288	0.650532	1,083,323	0.6505
Mar-98	1,789,054	0	1,789,054	0.620142	1,109,468	0.6201
Apr-98	1,314,878	0	1,314,878	0.644695	847,695	0.6447
May-98	1,498,188	0	1,498,188	0.615735	922,487	0.6157
Jun-98	1,310,822	0	1,310,822	0.681873	893,814	0.6819
Jul-98	1,630,267	2	1,630,265	0.637271	1,038,921	0.6373

GAVIN JURISDICTIONAL CALCULATION
PER SETTLEMENT IN CASE NO. 94-996-EL-AIR

MONTH/ YEAR	(1) NET GENERATION MWH	(2) GENERATION ASSIGNED TO SYS SALES MWH	(3) GENERATION REMAINING ON SYSTEM (1)-(2) MWH	(4) PUCO SYSTEM RATIO	(5) GENERATION ASSIGNED TO PUCO JURIS (3)X(4) MWH	(6) PUCO JURISDICTIONAL SHARE (5)/(1)
Aug-98	1,657,659	515	1,657,144	0.648756	1,075,082	0.6486
Sep-98	873,407	61	873,346	0.753456	658,028	0.7534
Oct-98	497,147	18,514	478,633	0.753474	360,638	0.7254
Nov-98	1,060,499	251	1,060,248	0.658813	698,505	0.6587
Dec-98	1,326,187	67,720	1,258,467	0.722151	908,803	0.6853
Jan-99	1,382,817	104,344	1,278,473	0.700809	895,965	0.6479
Feb-99	1,373,581	41,067	1,332,514	0.663004	883,462	0.6432
Mar-99	1,452,759	49,467	1,403,292	0.60319	846,452	0.5827
Apr-99	1,432,120	76,876	1,355,244	0.653187	885,228	0.6181
May-99	1,608,362	101,322	1,507,040	0.63964	963,963	0.5993
Jun-99	974,758	49,126	925,632	0.792287	733,366	0.7524
Jul-99	1,390,622	65,032	1,325,590	0.746362	989,370	0.7115
Aug-99	1,209,762	43,608	1,166,154	0.655576	764,503	0.6319
Sep-99	1,269,762	42,557	1,227,205	0.680352	834,931	0.6575
TOTAL (Since 12/91)	116,900,710	3,374,898	113,525,812		79,026,110	0.6760

Ohio Power Company
Repricing Fossil Generation Cost
Under Gavin Cap
Case 9901 98-101 (30 Day)

151 $ - Excl Coal Conversion	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	
Amos	6,532	6,553	5,933	6,568	6,282	6,531	
Cardinal 1	3,993	3,602	2,790	2,831	2,631	2,423	
Cardinal 2	95	94	359	7	5	922	
Cardinal 3	112	106	377	-	1	1,072	
Gavin	28,207	28,375	25,521	28,404	27,395	26,723	
Kammer	2,891	3,658	3,308	3,657	3,536	2,701	
Mitchell	11,206	11,403	10,039	10,399	8,994	9,091	
Muskingum 1-4	3,822	3,506	2,550	2,101	2,361	3,001	
Muskingum 5	4,169	4,182	3,824	4,173	4,061	4,235	
Sporn	5,291	5,238	4,652	4,521	4,532	5,133	
Total	66,318	66,716	59,352	62,661	59,798	61,831	376,676 3063 E4 379,739

GWh - Excl Coal Conversion						
Cardinal Unit 1	271	279	233	257	249	247
Gavin Plant	1,717	1,720	1,554	1,718	1,662	1,620
Muskingum Units 1-4	203	219	161	142	166	222
Muskingum Plant	540	556	469	478	493	563
Total	4,657	4,771	4,260	4,505	4,312	4,439

m/kWh - Excl CC's						
Cardinal Unit 1	14.72	12.91	11.97	11.01	10.58	9.82
Gavin Plant	16.43	16.50	16.42	16.53	16.49	16.50
Muskingum Units 1-4	18.81	16.00	15.81	14.78	14.22	13.55
Muskingum Plant	14.81	13.83	13.58	13.11	13.03	12.85
Total	14.24	13.98	13.93	13.91	13.87	13.93

Ohio Power Company
Repricing All Consumption
Gavin Plant
Case 9901

		Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99
Capped Price (c/mBtu)	(a)	167.90	167.90	167.90	168.07	168.07	168.07
Plant Consumption (tBtu)	(b)	16.8	16.9	15.2	16.9	16.3	15.9
Capped Fuel Cost ($000)		28,207	28,375	25,521	28,404	27,395	26,723

Comments:
(a) Cap calculation is based on forecasted index values.
(b) Consumption values are from AEP's Pool Forecast.

Thursday, December 3, 1998
CHDPP09A

PRODUCTION POOL MODEL
OHIO POWER
SUMMARY OF 151 FUEL EXPENSE BY PLANT, EXCLUDING COAL CONVERSION
CONTROLLERS FORECAST CASE 9901

8:51:53 am

	DECEMBER 1998	JANUARY 1999	FEBRUARY 1999	MARCH 1999	APRIL 1999	MAY 1999
AMOS	6,532.2	6,552.7	5,952.8	6,568.3	6,281.9	6,538.9
CARDINAL	5,678.7	7,072.6	6,771.3	7,499.7	7,437.0	10,678.0
GAVIN	27,813.6	27,066.7	23,931.5	26,268.7	25,117.7	26,420.5
KAMMER	2,890.6	3,657.8	3,387.7	3,657.3	3,536.3	2,701.0
MITCHELL	11,205.7	11,403.3	10,039.4	10,399.2	8,995.6	9,090.5
MUSKINGUM RIVER	8,381.1	8,795.1	7,347.6	7,311.5	7,702.7	9,524.2
SPORN	5,291.0	5,237.7	4,651.0	4,521.4	4,531.6	5,132.0
RACINE	.0	.0	.0	.0	.0	.0
COAL-FIRED GENERATION	67,792.7	69,786.0	61,982.1	66,226.3	63,600.0	67,878.6
GAS GENERATION	.0	.0	.0	.0	.0	.0
TOTAL FOSSIL STEAM GENERATION	67,792.7	69,786.0	61,982.1	66,226.3	63,600.0	67,878.6
NUCLEAR GENERATION	.0	.0	.0	.0	.0	.0
HYDRO GENERATION	.0	.0	.0	.0	.0	.0
TOTAL EXCLUDING TEST GENERATION	67,792.7	69,786.0	61,982.1	66,226.3	63,600.0	67,878.6
TEST GENERATION	.0	.0	.0	.0	.0	.0

TOTALS MAY NOT FOOT DUE TO ROUNDING

EFC RATE

ELECTRIC UTILITY BASE PERIOD SUMMARY REPORT FROM 12/01/98 TO 05/31/99
Company Name- OHIO POWER COMPANY Code 020008
ENERGY BALANCE SHEET (ACTUAL & ESTIMATED)

ENERGY SOURCES & EXPENSE	Fuel Only Cost ($)	Generation Level KWH	Fuel Only c/KWH
Fossil System Net Generation	379,738,000.00	26,943,600,000	1.40938
Nuclear System Net Generation	-	-	-
Other System Net Generation	-	90,100,000	0.00000
Test Generation	-	-	-
Purchased Energy	9,401,000.00	515,200,000	1.82473
Net Non-Monetary Interchange	//////////////////////////////	-	//////////////////////////////
Total Energy Available:	389,139,000.00	27,548,900,000	1.41254

ENERGY DISPOSITION & REVENUES	Fuel Only Charge ($)	Metered Sales Level KWH	Fuel Only c/KWH
Sales to Ultimate Consumers	254,829,000.00	16,558,000,000	1.53901
Sales for Resale	134,310,000.00	9,823,900,000	1.36718
Total Sales:	389,139,000.00	26,381,900,000	1.47502
	Gen. Level KWH	EFC Rule Sales (Metered KWH)	
Company Used Energy	0	Juris. (14 & 18):	0
Other Energy Disposed of or Lost	1,167,000,000	Non-Juris. (36):	0
Total Energy Disposed:	27,548,900,000	Total	0

FUEL COMPONENT DETERMINATION

CALCULATION OF FUEL COMPONENT	Includable Cost $	Corr. Gen. Level KWH	Rate c/KWH
Actual From ______ To ______			
Includable: Fossil System Net Gen:$;KWH			
Nuclear System Net Gen:$;KWH			
Other System Net Gen:$;KWH			
Purchased Energy:$;KWH			
Excludable: Sales for Resale:$;KWH			
Ultimate Consumers Sales:			
Non-Jur. Ultimate Cons:$;KWH			
Special Contract Jur:$;KWH			
Estimated From 12/01/98 TO 05/31/99			
Includable: Fossil System Net Gen:$;KWH	379,738,000.00	27,033,700,000	1.40468
Nuclear System Net Gen:$;KWH	-	-	-
Other System Net Gen:$;KWH	-	-	-
Purchased Energy:$;KWH	9,401,000.00	515,200,000	1.82473
Excludable: Sales for Resale:$;KWH	134,310,000.00	9,941,000,000	1.35107
Ultimate Consumers Sales:			
Non-Jur. Ultimate Cons:$;KWH	-	-	-
Special Contract Jur:$;KWH	39,412,000.00	3,719,400,000	1.05963
Fuel Component (FC)	215,417,000.00	13,888,500,000	1.55105

EFC RATE DETERMINATION*

Fuel Component (FC) from above	1.55105 ***
Ohio Coal Research and Development Component (OCRDC) from ER-19-S	0.00000
Fuel Component Reconciliation Rate (RA) from ER-16-S	(0.02889)
System Loss Adjustment (SLA) from ER-16-S	NA
EFC Rate Pursuant to Chapter 4901:1-11,OAC:**	1.52216

*EFC Rate = Fuel Component (FC) +(-) Ohio Coal Research and Development Component (OCRDC) +(-) Reconciliation Adj. (RA) +(-) System Loss Adj. (SLA).
**EFC Rate Applicable to Prospective Billings Beginning 06/01/98
***Fixed rate pursuant to settlement

As Filed Rate
98-101-EL-EFC

This Sheet Filed Pursuant to the Public
Utilities Commission of Ohio
Order No. 98-101-EL-EFC
PUCO Form ER-16-S

Date 03/12/98

By: Philip J. Nelson
Title: Senior Rate Consultant

EFC RATE

ELECTRIC UTILITY BASE PERIOD SUMMARY REPORT FROM 12/01/98 TO 05/31/99
Company Name OHIO POWER COMPANY Code 020009
ENERGY BALANCE SHEET (ACTUAL & ESTIMATED)

Filed # Less:
3925 000
+ 2068,000
5993 000

ENERGY SOURCES & EXPENSE	Fuel Only Cost ($)	Generation Level KWH	Fuel Only c/KWH
Fossil System Net Generation	373,745,000.00	26,943,600,000	1.38714
Nuclear System Net Generation	-	-	-
Other System Net Generation	-	90,100,000	0.00000
Test Generation	-	-	-
Purchased Energy	9,401,000.00	515,200,000	1.82473
Net Non-Monetary Interchange	//////////	-	//////////
Total Energy Available:	383,146,000.00	27,548,900,000	1.39079

ENERGY DISPOSITION & REVENUES	Fuel Only Charge ($)	Metered Sales Level KWH	Fuel Only c/KWH
Sales to Ultimate Consumers	254,829,000.00	16,558,000,000	1.53901
Sales for Resale	134,310,000.00	9,823,900,000	1.36718
Total Sales:	389,139,000.00	26,381,900,000	1.47502
	Gen. Level KWH	EFC Rule Sales (Metered KWH)	
Company Used Energy	0	Juris. (14 & 18):	0
Other Energy Disposed of or Lost	1,167,000,000	Non-Juris. (36):	0
Total Energy Disposed:	27,548,900,000	Total	0

FUEL COMPONENT DETERMINATION

CALCULATION OF FUEL COMPONENT*	Includable Cost $	Corr. Gen. Level KWH	Rate c/KWH
Actual From ______ To ______			
Includable: Fossil System Net Gen:$;KWH			
Nuclear System Net Gen:$;KWH			
Other System Net Gen:$;KWH			
Purchased Energy:$;KWH			
Excludable: Sales for Resale:$;KWH			
Ultimate Consumers Sales:			
Non-Jur. Ultimate Cons:$;KWH			
Special Contract Jur:$;KWH			
Estimated From 12/01/98 TO 05/31/99			
Includable: Fossil System Net Gen:$;KWH	373,745,000.00	27,033,700,000	1.38252
Nuclear System Net Gen:$;KWH	-	-	-
Other System Net Gen:$;KWH	-	-	-
Purchased Energy:$;KWH	9,401,000.00	515,200,000	1.82473
Excludable: Sales for Resale:$;KWH	134,310,000.00	9,941,000,000	1.35107
Ultimate Consumers Sales:			
Non-Jur. Ultimate Cons:$;KWH	-	-	-
Special Contract Jur:$;KWH	39,412,000.00	3,719,400,000	1.05963
Fuel Component (FC)	209,424,000.00	13,888,500,000	1.50790

EFC RATE DETERMINATION

Fuel Component (FC) from above	1.50790***
Ohio Coal Research and Development Component (OCRDC) from ER-19-S	0.00000
Fuel Component Reconciliation Rate (RA) from ER-15-S	(0.05136)
System Loss Adjustment (SLA) from ER-16-S	NA
EFC Rate Pursuant to Chapter 4901:1-11,OAC:**	1.45654

*EFC Rate = Fuel Component (FC) +(-) Ohio Coal Research and Development Component (OCRDC) +(-) Reconciliation Adj. (RA) +(-) System Loss Adj. (SLA).
**EFC Rate Applicable to Prospective Billings Beginning 06/01/98
***Fixed rate pursuant to settlement

10/5/99 Rate
98-101-EL-EFC
5/26/99 Order

This Sheet Filed Pursuant to the Public Utilities Commission of Ohio
Order No. 98-101-EL-EFC
PUCO Form ER-18-S

Date 03/12/98

By: Philip J. Nelson
Title: Senior Rate Consultant

OHIO POWER COMPANY
OPERATING LOSS AND INVESTMENT/SHUTDOWN COSTS
AS OF 12/31/99 ($000)
PUCO JURISDICTION

1.	Operating Loss From 6/1/95 - 11/30/98 [Exclusive of Investment/Shutdown (I/S) Costs]				$ 32,468
2.	Operating Loss From 12/01/98 - 12/31/99 [Exclusive of Investment/Shutdown (I/S) Costs]				$ 20,357
3.	Less Prior EFC Surplus per 92-101-EL-EFC:				
	Results from Period Ending 11/30/94			$ (11,980)	
	Results from 12/01/94 - 05/31/95			$ 5,842	
					$ (6,138)
	Total Operating Loss Exclusive of Investment/Shutdown Costs				$ 46,687
4.	Ohio Proportional Jurisdictional Share of Investment/Shutdown (I/S) Costs				
	Plant (Mine):	Total I/S*	Ohio Proport. Juris. Share	EFC Juris. I/S	
	Cardinal Unit 1 (Windsor)	$ 84,643	43%	$ 36,396	
	Muskingum River Units 1-4 (COCCO)	$ 126,800	43%	$ 54,524	
	Gavin (SOCCO)	$ 91,488	68%	$ 62,212	
		$ 302,931			
	Total Jurisdictional I/S Costs				$ 153,132 **
	Total Operating Loss and I/S Costs through 12/31/99				$ 199,819
5.	Gavin Recoveries From 12/01/98 through 12/31/99				$ (5,405)
	Net Deferred Fuel Cost Regulatory Assets as of 12/31/99				$ 194,414

* Amount that is estimated to be billed through 12/31/99
** Does not include normal amortizations

UNBUNDLING OF RA COMPONENT
OF TRANSITION PERIOD EFC

CSP FUEL RATE EFFECTIVE 10/05/99		$		RATE
FC (FUEL COMPONENT)	$	112,114,000	$	0.0134027
RA (RECONCILIATION ADJUSTMENT)	$	2,966,879	$	0.0003547
SLA (SYSTEM LOSS ADJUSTMENT)	$	(262,000)	$	(0.0000313)
EFC	$	114,818,879	$	0.0137261
KWHL	$	8,365,000,000		
RA UNBUNDLING				
UNDERRECOVERY	$	10,791,656	$	0.0012901
EA GAINS	$	(4,865,923)	$	(0.0005817)
EA REPRICING	$	(754,671)	$	(0.0000902)
OHIO COAL TAX CREDIT	$	(2,204,183)	$	(0.0002635)
TOTAL RA	$	2,966,879	$	0.0003547
KWHL PER FILING		8,365,000,000		
OPCO FUEL RATE EFFECTIVE 10/05/99				
FC (FUEL COMPONENT)	$	209,424,000	$	0.0150790
RA (RECONCILIATION ADJUSTMENT)	$	(7,133,612)	$	(0.0005136)
SLA (SYSTEM LOSS ADJUSTMENT)	$	-	$	-
EFC	$	202,290,388	$	0.0145653
KWHL	$	13,888,500,000		
RA UNBUNDLING				
OVERRECOVERY	$	(53,615)	$	(0.0000039)
EA GAINS	$	(7,079,997)	$	(0.0005098)
EA REPRICING	$	-	$	-
OHIO COAL TAX CREDIT	$	-	$	-
TOTAL RA	$	(7,133,612)	$	(0.0005136)
KWHL PER FILING		13,888,500,000		

.EXHIBIT NO.________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP
In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP

DIRECT TESTIMONY OF
ARMANDO A. PEÑA
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

INDEX TO DIRECT TESTIMONY OF
ARMANDO A. PEÑA
PUCO CASE NOS. 99-___-EL-ETP and
99-___-EL-ETP

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
ARMANDO A. PEÑA
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
CASE NO. 99-___-EL-ETP
AND
OHIO POWER COMPANY
CASE NO. 99-___-EL-ETP

Personal Data

Q. Please state your name and business address.

A. My name is Armando A. Peña. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. Please indicate by whom you are employed and in what capacity.

A. I am Senior Vice President-Finance, Treasurer & Chief Financial Officer of the American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP), the parent of Ohio Power Company (OPCO) and Columbus Southern Power Company (CSP).

Q. Please briefly describe your educational background and business experience.

A. I received a Bachelor's Degree in Industrial Engineering from the University of Miami, in 1966, and a Master's Degree in Management from the Massachusetts Institute of Technology, in 1968.

In June 1968, I was employed by Exxon Chemicals USA where I worked in various marketing research activities.

In August 1971, I was employed by AEPSC as a Staff Analyst in the Controller's Department. I was responsible for developing a computer model for corporate planning as well as other financial computer applications.

In September 1979, I joined AEPSC's Finance Department as Director of Banking and Security Analysts Relations. I was elected Assistant Vice President in 1982 and Vice President-Finance in May 1989.

In 1995 I was elected Treasurer of AEP and all of its subsidiary companies and was also elected to the AEPSC Board of Directors.

In 1996 I became Senior Vice President-Finance for AEPSC and in 1998 I became Chief Financial Officer. I am responsible for corporate finance, cash management, investor relations, risk management, credit, project finance and employee benefit funds. The corporate financing activities include the planning and execution of financing programs for AEP System Companies. These programs involve bank loans, commercial paper, first mortgage bonds, unsecured debt, preferred stock, common stock, asset sale/leaseback and various other instruments.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. My testimony addresses certain requirements of Am. Sub. S. B. No. 3 ("S. B. No. 3") as enacted by the Ohio General Assembly. I present and discuss the impact of the corporate separation requirements of S. B. No. 3 on the financial instruments of OPCO and CSP, each referred to as the Company. I am sponsoring EXHIBIT NO. ___ AAP-1, Debt Redemption Cost Analysis which was prepared under my supervision. I am also sponsoring Part B, §(G)(3).

Corporate Separation

Q. Is the Company proposing a corporate separation plan as part of its transition plan under S. B. No. 3?

A. Yes. My testimony and that of Company Witnesses Forrester and Knorr sponsor the Company's corporate separation plan as required in Section 4928.31(A)(2) of the Revised Code and the Commission's Rules.

Q. Please describe the corporate separation plan as it relates to your testimony.

A. The plan is to separate OPCO and CSP each into three legal entities by January 1, 2001: a generation company, a distribution company and a transmission company.

The plan will be implemented with appropriate recognition of the substantial overlapping financial arrangements that currently exist, as well as the regulatory requirements that could be imposed by federal agencies, such as the Securities and Exchange Commission under The Public Utility Holding Company Act of 1935. The goal is to separate each operating company in an orderly and economically efficient manner, and to minimize additional transition costs.

The plan would be to leave all generating assets in the existing legal structures of OPCO and CSP. The distribution and transmission assets would be transferred to new corporate entities. The distribution and transmission assets currently owned by OPCO and CSP would be transferred, if possible, to the distribution and transmission subsidiaries free of the lien of the mortgages. However, this may not be feasible. If the property could not be released (in the case of the CSP indenture, the transfer of assets subject to the lien is prohibited) those assets would be transferred to the transmission subsidiary or distribution subsidiary pursuant to a lease or by another contractual device that fully separates control over the assets. Under the OPCO indenture, the assets would be transferred subject to the lien of the mortgage, because a release from that lien may trigger the release of all the property, including generation property, which would entail substantial costs.

Each of the transmission and distribution companies will create a new indenture for Senior Unsecured Notes, effective January 1, 2001. All debt and lease obligations existing as of the asset transfer date will remain with the generation company. However, leases attributable to identifiable distribution and transmission assets will be transferred to their respective new entities if permitted under existing documentation; otherwise lessor consent may be required. The distribution and transmission assets will be released from the mortgage indenture on the transfer date subject to meeting the necessary requirements.

It is our intention to issue new unsecured debt (subject to market conditions prevailing at the time of issuance) at the distribution and the transmission companies on or after the asset transfer date, but in no event later than the end of the Market Development Period. The proceeds of these issuances will be paid to the generation company which in turn will repay or defease existing indebtedness.

It may not be possible, however, to defease or repay the debt of OPCO and CSP without incurring certain costs.

Q. What are the costs of implementing immediate legal separation?

A. If the transmission and distribution companies are required to issue all new debt on the asset transfer date, and repay and/or defease existing debt obligations, we estimate that the Company would incur in excess of $23,000,000 for OPCO or $24,000,000 for CSP in call premiums and/or defeasance costs. By being flexible over time, the Company expects to minimize the costs incurred. [See EXHIBIT NO. ___ AAP-1.]

Q. How will the complete separation of the existing companies' financial overlaps occur?

A. The plan is to unwind the financial overlaps as soon as it is economically and legally practical. This will involve refinancing of substantially all the obligations of OPCO and CSP over a period of time. In most states, even where the type of corporate separation required in Ohio is not mandated, asset refinancing through securitization was provided as a vehicle to provide the cash for, and reduce the costs of, any unwind. Since securitization of the type authorized in other states is not available in Ohio, it will take more time to economically unwind the existing obligations without incurring additional transition costs.

The plan involves: a) assigning specific debt that can be identified to the individual assets, such as pollution control debt on generating units and b) leaving the remaining debt and preferred stock obligations with the generation company because such obligations cannot be transferred or assigned to the transmission company or the distribution company. Assignments of all the debt (not partial amounts) can only occur if OPCO or CSP transfers or assigns "all or substantially all" of their assets. In such case, the transferee or assignee assumes all of the indebtedness of the transferor or assignor. Because OPCO and CSP will retain all the generation assets, the Company does not believe the "all or substantially all" standard will be triggered. Of course, debt and preferred stock obligations will be retired, and replaced in a manner that does not create, and ultimately eliminates, future financial overlaps.

Q. Can the Company implement complete financial separation by January 1, 2001?

A. Not without substantial cost. Therefore the Company is fulfilling a legal separation with overlapping financial obligations. Complete separation involves unwinding financial instruments such as the first mortgage bond indenture that have restrictive provisions regarding the disposition or transfer of assets. All existing debt will remain with the generating company. New debt is expected to be raised at the transmission and distribution company levels, the proceeds of which will be provided to the generation company to redeem a portion of the existing debt, including some of the first mortgage bonds, senior notes and junior subordinated debentures. One obstacle is that if the property cannot be released, the bondholders may demand additional monetary consideration to allow OPCO and CSP to transfer the assets. In addition, if there is a debt exchange which exchanges notes from the generation company to the transmission company or distribution company, noteholders could require that substantial premiums be paid which would increase the Company's transition costs.

Q. Please describe the implications under the first mortgage bond indentures of each operating company related to the transfer of ownership of the transmission and distribution assets.

A. The Companies' goal is to release all the transmission and distribution property from the mortgages. If these assets cannot be released from the CSP Mortgage, the transfer will occur pursuant to a lease or other contractual arrangements that transfer operation, maintenance and control of the assets to the transmission and distribution companies. For OPCO, the assets would be transferred to an affiliate subject to the lien of its indenture.

Q. Please describe the provisions within the first mortgage bonds indentures that govern the transfer of assets and release of liens on that property.

A. The liens can be released pursuant to the provisions of each operating company's first mortgage bond indenture, by pledging property that has not previously been used for other purposes under the indenture, using previously retired and available bonds, or depositing cash with the trustee.

The amount of retired bonds and property additions available to replace assets under the mortgage indenture is limited, but appears to be sufficient to release the transmission and distribution property. New debt will be issued by the transmission and distribution companies, the proceeds of which will be provided to the generating company to redeem outstanding debt.

Q. What physical assets will be transferred to the transmission and distribution companies?

A. The distribution company will hold distribution and general property required to provide utility services within its regulated service territories. The transmission company will hold transmission and general property required to provide transmission services. Those physical assets not transferred, which include predominantly generation assets, will remain with the generation company. As explained by Company Witness Forrester, the transition costs, including generation related regulatory assets that were associated with the previously bundled CSP and OPCO will be transferred to the new distribution subsidiaries.

Q. Which *financial obligations will remain* with OPCO and CSP?

A. All financial obligations including the First Mortgage Bonds, Senior Unsecured Notes, Pollution Control Bonds, Preferred Stock and Lease Obligations, remain with OPCO and CSP with the exception of leases on identifiable distribution and transmission assets which can be efficiently transferred to the new distribution and transmission companies, if possible.

Lease Arrangements

Q. Your comments regarding the financial obligations the OPCO and CSP and the transmission company and the distribution company referenced Lease Obligations. Please describe the plans relating to these transactions.

A. With regard to the generation company, the plan is to continue to have the company as lessee for assets related to generating activities such as the OPCO Gavin Lease.

With regard to the leases of assets related to distribution or transmission activities, it is the Company's intention to transfer these obligations to the new distribution and transmission companies. Such a transfer would be subject to the approval of each lessor, and it is the intention of the Company to establish a plan to effect such transfers during the Market Development Period.

Q. What will the capital obligations be at the start of the Market Development Period for OPCO and CSP?

A. The following table depicts the projected capital obligations of OPCO and CSP as of January 1, 2001. The table excludes the debt equivalent of the sale/leaseback obligations.

Company	Debt	Preferred Stock	Total
OPCO	$1,108,135,000	$25,952,830	$1,134,087,830
CSP	931,745,000	20,000,000	951,745,000

Q. Does this conclude your testimony?

A. Yes.

Exhibit No. ______-AAP-1

American Electric Power
Debt Redemption Cost Analysis
If called on January 1, 2001

Security	*Columbus Southern Power*	*Ohio Power*	*Total*
First Mortgage Bonds	$ 20,300,000	$ 12,520,000	$ 32,820,000
Junior Subordinated Debentures	880,000	1,140,000	2,020,000
Unsecured Notes	2,720,000	8,240,000	10,960,000
Preferred Stock	140,000	1,260,000	1,400,000
	$ 24,040,000	$ 23,160,000	$ 47,200,000

EXHIBIT NO.________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP
In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP

DIRECT TESTIMONY OF
MARK A. PYLE
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

INDEX TO DIRECT TESTIMONY OF
MARK A. PYLE
PUCO CASE NOS. 99-___-EL-ETP and
99-___-EL-ETP

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
MARK A. PYLE
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
CASE NO. 99-___-EL-ETP
AND
OHIO POWER COMPANY
CASE NO. 99-___-EL-ETP

Personal Data

Q. Please state your name and business address.

A. My name is Mark A. Pyle. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. Please indicate by whom you are employed and in what capacity.

A. I am the Manager of State and Local Taxes for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP) the parent of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCO).

Q. Please briefly describe your educational background and business experience.

A. I earned a Bachelor of Science Degree with a major in accounting from the University of Dayton in 1983 and a Masters in Business Administration from Franklin University in 1995. I am a Certified Public Accountant licensed in Ohio since 1985. I am also a member of the Ohio Society of Certified Public Accountants and the Tax Executives Institute.

I joined the AEPSC Tax Department in 1987 as a tax accountant. Since 1987 I have served in the AEPSC Tax Department as Senior Tax Accountant, Supervisor – State Tax Compliance, and Manager – State & Local Taxes. In my present position I am responsible for managing the state and local taxes of AEP and its subsidiaries, including Columbus Southern Power Company (CSP) and Ohio Power Company (OPCO). I am also responsible for coordinating the development of state and local tax data to be provided by the AEPSC Tax Department in rate proceedings. Prior to joining AEPSC I worked for Ernst & Young, LLP (Ernst & Whinney) from 1983 to 1987 in various tax positions.

Purpose of Testimony

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

A. The purpose of my testimony is to identify the state and local tax changes brought about by the passage of Am. Sub. S. B. No. 3 and the timing and amount of the respective tax changes. I am also sponsoring certain adjustments reported in Part A, Schedule UNB-6.1, Schedule-By-Schedule Revenue Adjustment Summary, including; embedded gross receipts taxes, embedded property taxes, municipal income taxes and Ohio franchise taxes.

My testimony only focuses on the amount of rate riders discussed by Company Witness Forrester. Company Witness Roush provides tariff level information in his testimony and supporting documentation.

List of Exhibits

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

<u>Description</u>

1.	Kilowatt-hour Excise Taxes	EXHIBIT NO.____	MAP-1
2.	Public Utility Excise Taxes (Gross Receipts Taxes)	EXHIBIT NO.____	MAP-2
3.	Personal Property Taxes	EXHIBIT NO.____	MAP-3
4.	Municipal Income Taxes	EXHIBIT NO.____	MAP-4
5.	Ohio Franchise Taxes	EXHIBIT NO.____	MAP-5

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. What data was used in the preparation of the exhibits that you are sponsoring?

A. Kilowatt-hour consumption information presented in CSP Case No. 91-418-EL-AIR and OPCO Case No. 94-996-EL-AIR was used to develop an estimated kilowatt-hour excise tax amount. Gross receipts tax schedules from CSP Case No. 91-418-EL-AIR and OPCO Case No. 94-996-EL-AIR, personal property tax schedules from CSP Case No. 91-418-EL-AIR and OPCO Case No. 94-996-EL-AIR, and PUCO Staff work papers from CSP Case No. 91-418-EL-AIR and OPCO Case No. 94-996-EL-AIR were used in the preparation of embedded tax amounts included in current rates. In the preparation of the municipal income taxes and Ohio franchise taxes, 1998 actual CSP and OPCO data was used to prepare the exhibits included herein, including; net operating income, separate company federal taxable income, payroll data, property records, and revenue information.

Description of Tax Changes

Q. Please describe the tax changes in Am. Sub. S. B. No. 3.

A. The tax changes in Am. Sub. S. B. No. 3 revise Ohio tax statutes in anticipation of changes in the types of businesses and transactions in a deregulated market place, and place Ohio-based deregulated generation on an equal tax footing with other competitive businesses inside and outside the State of Ohio.

Through exemption from the gross receipts tax, reduction in the listing percentage of generation and general personal property taxes, and the imposition of the Ohio franchise tax and municipal income taxes, generation facilities in Ohio will be on the same tax footing as other industrial facilities in the state. Because the tax changes created a shortfall in state and local tax collections a kilowatt-hour excise tax imposed on electric distribution companies was added for the purpose of maintaining revenue for public education and state and local government operations.

Q. Which tax changes will affect CSP and OPCO and what are the effective dates?

A. The tax changes affecting CSP and OPCO are listed below and include the respective effective dates:

Kilowatt-hour Excise Tax	Begins	05/01/01
Public Utility Excise Tax (Gross Receipts)	Ends	04/30/02

Property Tax Reduction	Effective	01/01/01
Ohio Franchise Tax	Begins	01/01/02
Municipal Income Tax	Begins	01/01/02

Unbundled Rate Schedules – Tax Recovery Methodology

Q. Which taxes, specifically addressed in Am. Sub. S. B. No. 3, relate to unbundled rates?

A. Ohio Revised Code (ORC) Section 4928.34 indicates that unbundled rates shall be adjusted for any changes in the taxation of electric utilities and retail electric service resulting from the passage of Am. Sub. S. B. No. 3. ORC Section 4928.35 provides that the unbundled rate schedules should reflect tax law changes that have a material effect on utilities or if utilities receive any refund as a result of the resolution of utility property valuation litigation.

Q. Which tax changes meet the criteria established in ORC Sections 4928.34 and should be reflected as adjustments in the computation of unbundled rates of CSP and OPCO?

A. The following taxes should be included as adjustments in the computation of unbundled rates of CSP and OPCO: kilowatt-hour excise taxes, gross receipts taxes, personal property taxes, Ohio franchise taxes, deferred Ohio franchise taxes, municipal income taxes, and deferred municipal income taxes.

Determination of Kilowatt-hour Tax Rate Rider Amounts

Q. How do you recommend the unbundled rate rider amounts for the introduction of the kilowatt-hour excise tax be determined?

A. The kilowatt-hour excise tax should be determined based on the computation levels specified in the ORC Section 5727.81 for each customer. The statute provides that an electric distribution company shall base the monthly tax on the kilowatt-hours of electricity distributed in a thirty-day period by the company through a meter to an end user in this state. A second option permits the electric distribution company to compute the tax using a daily average usage for a measurement period instead of a thirty-day period. CSP and OPCO recommend using the daily average usage method to allow for measurement periods within the normal billing cycles that do not equal thirty days.

Based on kilowatt-hour consumption levels reported in CSP Case No. 91-418-EL-AIR it is estimated that CSP would have incurred a kilowatt-hour excise tax liability of $50,519,870 for the twelve-month period ended December 31, 1991 (EXHIBIT NO.____ MAP-1, Page 1 of 2). Based on kilowatt-hour consumption levels reported in OPCO Case No. 94-996-EL-AIR it is estimated that OPCO would have incurred a kilowatt-hour excise tax liability of $71,883,577 for the twelve-month period ended March 31, 1995 (EXHIBIT NO.____ MAP-1, Page 2 of 2). Kilowatt-hour consumption information was provided to me by Company Witness Roush and the information reflected usage by self-assessing customers and federal government customers.

Determination of Gross Receipts Tax Rate Rider Amounts

Q. How do you recommend the unbundled rate rider amounts for the exemption from gross receipts tax be determined?

A. The gross receipts tax rate rider amounts should reflect the exemption from gross receipts tax by removing the entire cost reflected in current revenue (see also Part A, Schedule UNB-6.1) in the last rate case. CSP Case No. 91-418-EL-AIR provided for jurisdictional gross receipts taxes of $ 39,484,000 (EXHIBIT NO.____ MAP-2, Page 1 of 2) and OPCO Case No. 94-996-EL-AIR provided for jurisdictional gross receipts taxes of $48,912,000 (EXHIBIT NO.____ MAP-2, Page 2 of 2).

Determination of Personal Property Tax Rate Rider Amounts

Q. How do you recommend the unbundled rate rider amounts for the reduction in embedded personal property taxes be determined?

A. The personal property tax rate rider should reflect the reduction in personal property taxes by adjusting the personal property tax cost reflected in revenue in the last rate case for the changes in classification and listing percentage provided in Am. Sub. S. B. 3. CSP Case No. 91-418-EL-AIR provided for jurisdictional personal property taxes of $47,152,449 and OPCO Case No. 94-996-EL-AIR provided for jurisdictional personal property taxes of $60,675,278. For CSP the reduction in embedded personal property taxes created by the provisions of Am. Sub. S. B. 3 equals $15,483,225 based on a revised jurisdictional personal property tax level of $31,669,223 (EXHIBIT NO.____ MAP-3, Page 1 of 2). For OPCO the reduction in embedded personal property taxes created by the provisions of Am. Sub. S. B. 3 equals $20,312,647 based on a revised jurisdictional personal property tax level of $40,362,631 (EXHIBIT NO.____ MAP-3, Page 2 of 2). Jurisdictional factors and computation methodology from CSP Case No. 91-418-EL-AIR and OPCO Case No. 94-996-EL-AIR were used to compute the reduction in embedded personal property taxes.

Q. Do the embedded personal property tax reductions you are proposing in this filing include amounts related to the refund of utility personal property taxes resulting from property valuation litigation?

A. No. Neither CSP nor OPCO have received any refunds of personal property taxes resulting from property valuation litigation.

Determination of Municipal Income Tax Rate Rider Amounts

Q. How do you recommend the unbundled rate rider amounts for the introduction of municipal income taxes be determined?

A. Municipal income taxes are a new tax for electric companies in Ohio; however, the municipal income tax has been assessed on individuals and businesses in Ohio for many years. As such, the method for computing municipal taxable income and the apportionment of that income to municipalities is well established. Just as there are differences between the States in determining taxable income, Ohio municipalities do not employ a uniform approach in defining what constitutes municipal taxable income, how income is allocated and apportioned, tax rates, payment dates or administration. Because of these variations, the computation and payment of municipal income taxes by electric companies that will be required to file in many municipalities is extremely complex. State Representative Motley (R-West Carrollton), Chair of the House Ways and Means Committee, has introduced H.B. No. 483 which would greatly simplify the procedures for paying municipal income taxes by electric companies. We look forward to working with Representative Motley with the hope that legislation will be enacted that will make filing and paying municipal income taxes easier for electric companies. The rate rider amount for municipal income taxes should be computed by applying a methodology similar to the approach used for determining Ohio franchise taxable income. An estimated composite tax rate of 1.8877 percent (EXHIBIT NO.____ MAP-4, Page 3 of 6) should be used to calculate the tax for CSP while taking into consideration income allocation and apportionment. An estimated composite tax rate of 1.4792 percent (EXHIBIT NO.___ MAP, Page 6 of 6) should be used to calculate the tax for OPCO while taking into consideration income allocation and apportionment. An aggregate computation provides an estimated level of municipal income taxes for CSP of $1,559,739 (EXHIBIT NO.___MAP-4, Page 1 of 6) and an estimated level of municipal income taxes for OPCO of $976,415 (EXHIBIT NO.___ MAP-4, Page 4 of 6). The amounts for CSP and OPCO include both current and deferred municipal income taxes. Because of the inconsistency in the administration of municipal income taxes in Ohio and the continuing development of internal computer information sources, it is not practical at this time to compute a separate municipal income tax for each municipality on a stand alone basis.

Determination of Ohio Franchise Tax Rate Rider Amounts

Q. How do you recommend the unbundled rate rider amount for the introduction of the Ohio Franchise tax be determined?

A. The Ohio Franchise tax rate rider should be computed by applying provisions of the new Ohio franchise tax laws to CSP and OPCO's 1998 operating income and separate company taxable income to provide the most recent verifiable information available. Separate company taxable income was adjusted to eliminate the impact of non-operating income and the effect of permanent differences was eliminated in determining deferred Ohio franchise taxes. Income allocation and apportionment rules were applied when determining the level of total income that is taxable for Ohio franchise tax purposes.

Because this is the first time the Ohio franchise tax applies to electric companies, a deduction for the franchise tax is not included in 1998 separate company taxable income. Therefore, the statutory tax rate of 8.5 percent should be adjusted to 7.78 percent [8.5%*(1-8.5%)]. The rate adjustment reflects the current Ohio franchise tax accrual required by Generally Accepted Accounting Principles (GAAP) that is also deductible for federal and Ohio franchise tax purposes.

The law provides that only two-thirds of the 2001 Ohio franchise taxable income will be taxable for the 2002 franchise tax year. For franchise tax year 2003 the full amount of the 2002 Ohio franchise taxable income is subject to tax. I estimated the first year Ohio franchise tax, before credits, for CSP to be $8,480,149 (EXHIBIT NO.____MAP-5, Page 1 of 6) and I estimated the first year level of Ohio franchise tax, before credits, for OPCO to be $11,760,978

(EXHIBIT NO.___ MAP-5, Page 4 of 6). In the second year I estimate that the Ohio franchise tax, before credits, for CSP to be $12,050,607 (EXHIBIT NO.____ MAP-5, Page 2 of 6) and I estimate that the Ohio franchise tax, before credits, for OPCO to be $15,696,730 (EXHIBIT NO.___ MAP-5, Page 5 of 6). The amounts for CSP and OPCO include both current and deferred municipal income taxes.

Discussion of SFAS 109, Deferred Income Tax Requirements

Q. How do you recommend the unbundled rate rider amounts reflect the requirements of Statement of Financial Accounting Standards (SFAS) 109 for Ohio franchise and municipal income taxes?

A. To provide for the proper matching of income and expenses and to comply with GAAP, deferred tax accounting under SFAS 109 should be applied with regard to all state franchise (income) taxes and municipal income taxes. Deferred state income taxes and deferred municipal income taxes should be included with the current Ohio franchise tax and current municipal income taxes when computing the rate rider amounts for taxes based on income.

Q. How does the Ohio basis adjustment enacted as part of Am. Sub. S. B. No. 3 to alleviate the one time charge to earnings from the application of SFAS 109 impact base rates?

A. The Ohio basis adjustment was included in Am. Sub. S. B. No. 3 to mitigate the substantial deferred state income tax expense and deferred municipal income taxes expenses which would have been charged against the Company's earnings in the year the statutes became effective. The Ohio tax basis adjustment only applies to assets in place at the effective date of the state franchise tax and municipal income taxes on utilities. Temporary differences resulting from non-property income or expenses are not covered by the basis adjustment, nor are property related temporary differences originating after December 31, 2001.

Schedule of Effective Dates for Rate Riders

Q. When do you propose the rate riders to take effect?

A. The rate rider for the new kilowatt-hour excise tax should be effective May 1, 2001. The rate rider for the elimination of the embedded gross receipts taxes should be effective May 1, 2002. The rate rider for the reduction in personal property taxes should be effective January 1, 2001. The rate rider for municipal income taxes and deferred municipal income taxes should be effective January 1, 2002. The rate rider for the Ohio franchise tax and deferred state income taxes should be effective January 1, 2001.

Q. Why are you proposing an effective date of May 1, 2002 for the embedded gross receipts tax rider instead of May 1, 2001?

A. The final privilege year for the gross receipts tax begins May 1, 2001 and ends April 30, 2002. The final measurement period for the gross receipts tax ends April 30, 2001. For financial purposes, the tax is prepaid and amortized to expense ratably over the privilege year and not the measurement year. Both CSP and OPCO will be required to amortize the final year of prepaid gross receipts taxes to expense over the privilege year ending April 30, 2002. If the reduction in embedded gross receipts tax rider were to begin earlier than May 1, 2002, both

CSP and OPCO would be left with an unamortized, prepaid gross receipts tax asset of approximately $46,000,000 and $50,000,000, respectively, that would not be recovered during the privilege year. As a result, the financial responsibility for the expense would be shifted to the utilities and their shareholders.

Q. ORC Section 4928.34(A)(6) states that, "(t)o the extent such total annual amount of the tax-related adjustment is greater than or less than the comparable amount of the total annual tax reduction experienced by the electric utility as a result of the provisions of Sub. S. B. No. 3 of the 123rd General Assembly, such difference *shall be addressed by the Commission through accounting procedures, refunds, or* an annual surcharge or credit to customers, or through other appropriate means, to avoid placing the financial responsibility for the difference upon the electric utility or its shareholders." Does the May 1, 2002 effective date meet the requirements of ORC Section 4928(A)(6)?

A. Yes. By selecting May 1, 2002 as the effective date of the embedded gross receipts tax rider, the Commission avoids placing the financial responsibility for the difference in the amount of the tax-related adjustments on the utilities or their shareholders. In addition, this method provides for no more than the full recovery of the prepaid gross receipts tax by the utility.

Q. Why are you proposing an effective date of January 1, 2001 for the Ohio franchise tax instead of January 1, 2002?

A. For the financial reporting of income taxes, GAAP requires income taxes be accrued during the period the income is earned. The Ohio franchise tax beginning January 1, 2002 is based on two thirds of the taxable income earned in 2001. Due to the nature of the Ohio franchise tax, the accounting profession has issued guidance with regard to the timing of the expense for GAAP. In AICPA Interpretation #24, Franchise Taxes Based on Income, it was determined that the income tax portion of the Ohio franchise tax should be accrued in the year the income was earned (Issued March, 1972). The Emerging Issues Task Force (EITF) addresses the issue with respect to Texas, but the same logic and guidance applies to Ohio because the Texas franchise tax is identical to the Ohio franchise tax with respect to the measurement period and the reporting period. In EITF 91-8 the task force concluded "(t)he portion of the current tax liability based on income should be accrued with a charge to income during the period in which the income is earned." Therefore to properly match tax expense with the income earned, the effective date must be January 1, 2001.

Q. Does this conclude your testimony?

A. Yes.

Columbus Southern Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

Kilowatt Hour Usage		Kilowatt-hour Excise Taxes 1991
First 2000 kWh		5,201,691,125
Next 13000 kWh		1,567,283,568
Over 15000 kWh		5,444,927,718
Total kWh		12,213,902,411
kWh Tax Rates		
First 2000 kWh	$	0.00465
Next 13000 kWh	$	0.00419
Over 15000 kWh	$	0.00363
kWh Tax		
First 2000 kWh		24,187,864
Next 13000 kWh		6,566,918
Over 15000 kWh		19,765,088
Total kWh Tax		50,519,870

Effective Date 05/01/01

Ohio Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

Kilowatt Hour Usage		**Kilowatt-hour Excise Taxes Yr End 03/31/1995**
First 2000 kWh		6,699,054,083
Next 13000 kWh		2,236,122,279
Over 15000 kWh		8,640,116,830
Total kWh		17,575,293,192
kWh Tax Rates		
First 2000 kWh	$	0.00465
Next 13000 kWh	$	0.00419
Over 15000 kWh	$	0.00363
kWh Tax		
First 2000 kWh		31,150,601
Next 13000 kWh		9,369,352
Over 15000 kWh		31,363,624
Total kWh Tax		71,883,577

Effective Date 05/01/01

Columbus Southern Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

(Gross Receipts Tax)	**Public Utility Excise Taxes**	
Ohio Jurisdiction		
Staff Adjusted Expenses	33,623,000	
Proforma Adjustments	5,861,000	
Proforma Gross Receipts Tax	39,484,000	(a)

Effective Date 05/01/02

(a) Case No. 91-418-EL-AIR

Ohio Power Company
Electric Transiton Plan
Case No. 99-___-EL-ETP

EXHIBIT NO. ___ MAP-2

(Gross Receipts Taxes)	**Public Utility Excise Tax**	
Ohio Jurisdiction		
Adjusted Jurisdiction (As Filed)	45,781,000	(a)
Proforma Adjustments	7,229,000	(a)
Settlement Adjustment	(4,098,000)	(b)
Embedded Gross Receipts Tax	48,912,000	

Effective Date 05/01/02

(a) Case No. 94-996-EL-AIR
(b) Based on settlement increase of $66,000,000

Applicant Proposed Increase:			
Operating Revenue	100.000000	(a)	152,384,000
Less: Uncollectibles	0.001298	(a)	197,794
Revenue After Uncollectibles	99.998702	(a)	152,186,206
Less: Ohio Gross Receipts Tax	4.749938	(a)	7,228,750
Income Before State Income Tax	95.248764	(a)	
Rounded			7,229,000
Settlement Adjustment to Proposal:			
Operating Revenue	100.000000	(b)	(86,384,000)
Less: Uncollectibles	0.129800	(b)	(112,126)
Revenue After Uncollectibles	99.870200	(b)	(86,271,874)
Less: Ohio Gross Receipts Tax	4.743835	(b)	(4,097,914)
Income Before State Income Tax	95.126365	(b)	
Rounded			(4,098,000)

Columbus Southern Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

	Personal Property Taxes	
Property Taxes Included In Base Rates	48,812,058	
Less: Revised Property Taxes	32,783,875	
Property Tax Reduction	16,028,183	
Jurisdictional Allocation	96.60%	
Jurisdictional Property Tax Reduction	15,483,225	
Production Factor	0.978315	
General Property Factor	0.021685	
Production Property	15,147,471	<=======
General Property	335,754	<=======

Ohio Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

	Personal Property Taxes	
Property Taxes Included In Base Rates	60,675,278	
Less: Revised Property Taxes	40,362,631	
Jurisdictional Property Tax Reduction	20,312,647	
Production Property	0.975041	
General Property	0.024959	
Production Property	19,805,664	<=======
General Property	506,983	<=======

Columbus Southern Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

	Municipal Income Taxes 2002
Net Operating Income (1998)	211,137,712
Additions:	
State & Local Income Taxes:	
Ohio Franchise Taxes	-
Ohio Local Income Taxes	-
Other State & Local Taxes	3,336
Federal Income Taxes	77,091,863
Allowance for Other Funds	402,014
Deductions:	
Net Interest Charges	(77,817,338)
Pre-Tax Operating Income	210,817,587
Less Permanent Differences	
Deferred Comp Insurance Premium	-
Deferred Comp CSV Earnings	-
Deferred Comp Interest Expense	-
Meals and T&E	65,321
COLI Premium Expense	-
COLI Earnings	(5,409,835)
COLI Death Benefits	(2,490,436)
COLI Interest Expense	2,832,123
Leased Luxury Auto	5,954
Total Permanent Differences	(4,996,873)
Adjusted Pre-Tax Operating Income	205,820,714
Weighted Average Municipal Income Tax Rate	1.8877%
Apportionment Factor	0.507516
Effective Municipal Income Tax Rate	0.95800%
Total Municipal Income Tax Expense	(1,971,762)
Federal Taxable Income	179,999,429
Add: Net Operating Loss	-
Add: Special Deductions	1,348,160
Taxable Inc Before NOL & Special Deductions	181,347,589
Add: State & Local Income Tax	3,336
Less: Other Income and Deductions - Book	(6,373,871)
Less: Non Operating Temporary Differences	4,717,086
Municipal Operating Taxable Income	183,007,710
Weighted Average Municipal Income Tax Rate	1.8877%
Apportionment Factor	0.507516
Effective Municipal Income Tax Rate	0.95800%
Current Municipal Income Tax Expense	(1,753,214)
Deferred Municipal Income Tax Expense	(218,548)
2002 Municipal Income Tax Accrual	(1,971,762)
2002 Jurisdictional Municipal Income Tax Accrual	(1,559,739)

Jurisdictional amount provided by Company Witness Roush.

Ohio Power Company
Electric Transiton Plan
Case No. 99-___-EL-ETP

	Municipal Income Taxes 2002
Net Operating Income (1998)	287,523,466
Additions:	
State & Local Income Taxes:	
Ohio Franchise Taxes	-
Ohio Local Income Taxes	-
Other State & Local Taxes	2,742,535
Federal Income Taxes	117,082,995
Allowance for Other Funds	104,047
Deductions:	
Net Interest Charges	(77,391,010)
Pre-Tax Operating Income	330,062,033
Less Permanent Differences:	
Deferred Comp Insurance Premium	9,330
Deferred Comp CSV Earnings	(73,808)
Deferred Comp Interest Expense	-
Meals and T&E	169,347
COLI Premium Expense	-
COLI Earnings	(9,927,503)
COLI Death Benefits	(5,695,318)
COLI Interest Expense	5,093,282
Leased Luxury Auto	5,666
Total Permanent Differences	(10,419,004)
Adjusted Pre-Tax Operating Income	319,643,029
Weighted Average Municipal Income Tax Rate	1.4792%
Apportionment Factor	0.238831
Effective Municipal Income Tax Rate	0.35330%
Total Municipal Income Tax Expense	(1,129,299)
Federal Taxable Income	229,717,097
Add: Net Operating Loss	-
Add: Special Deductions	1,964,191
Taxable Inc Before NOL & Special Deductions	231,681,288
Add: State & Local Income Tax	2,742,535
Less: Other Income and Deductions	(9,428,744)
Less: Non Operating Temporary Differences	2,382,006
Municipal Operating Taxable Income	241,470,561
Weighted Average Municipal Income Tax Rate	1.4792%
Apportionment Factor	0.238831
Effective Municipal Income Tax Rate	0.35330%
Current Municipal Income Tax Expense	(853,115)
Deferred Municipal Income Tax Expense	(276,184)
2002 Municipal Income Tax Accrual	(1,129,299)
2002 Jurisdictional Municipal Income Tax Accrual	(976,415)

Jurisdictional amount provided by Company Witness Roush.

Columbus Southern Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

	Ohio Franchise Taxes 2001
Net Operating Income (1998)	211,137,712
Additions:	
Federal Income Taxes	77,091,863
Ohio Franchise Taxes	-
Allowance for Other Funds	402,014
Deductions:	
Net Interest Charges	(77,817,338)
Pre-Tax Operating Income	210,814,251
Less Permanent Differences:	
Deferred Comp Insurance Premium	-
Deferred Comp CSV Earnings	-
Deferred Comp Interest Expense	-
Meals and T&E	65,321
COLI Premium Expense	-
COLI Earnings	(5,409,835)
COLI Death Benefits	(2,490,436)
COLI Interest Expense	2,832,123
Leased Luxury Auto	5,954
Total Permanent Differences	(4,996,873)
Adjusted Pre-Tax Operating Income	205,817,378
Adjusted Statutory State Income Tax Rate	7.7775%
Apportionment Factor	0.951996
Effective State Income Tax Rate	7.40410%
Total State Income Tax Expense	(15,238,924)
Federal Taxable Income	179,999,429
Add: Net Operating Loss	-
Add: Special Deductions	1,348,160
Taxable Inc Before NOL & Special Deductions	181,347,589
Add: Ohio Franchise Taxes	-
Less: Other Income and Deductions - Book	(6,373,873)
Less: Non Operating Temporary Differences	4,717,086
Ohio Operating Taxable Income	183,004,376
Adjusted Statutory State Income Tax Rate	7.7775%
Apportionment Factor	0.951996
Effective State Income Tax Rate	7.40410%
Current State Income Tax Expense	(13,549,827)
First Year Limitation	66.6667%
First Year Current State Income Tax Expense	(9,033,223)
Deferred State Income Tax Expense	(1,689,097)
2001 Ohio Franchise Tax Accrual	(10,722,320)
2001 Jurisdictional Franchise Tax Accrual	(8,480,149)

Jurisdictional amount provided by Company Witness Roush.

Adjusted Statutory State Franchise Tax Rate[.085*(1-.085)]

Columbus Southern Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

	Ohio Franchise Taxes 2002
Net Operating Income (1998)	211,137,712
Additions:	
Federal Income Taxes	77,091,863
Ohio Franchise Taxes	-
Allowance for Other Funds	402,014
Deductions:	
Net Interest Charges	(77,817,338)
Pre-Tax Operating Income	210,814,251
Less Permanent Differences:	
Deferred Comp Insurance Premium	-
Deferred Comp CSV Earnings	-
Deferred Comp Interest Expense	-
Meals and T&E	65,321
COLI Premium Expense	-
COLI Earnings	(5,409,835)
COLI Death Benefits	(2,490,436)
COLI Interest Expense	2,832,123
Leased Luxury Auto	5,954
Total Permanent Differences	(4,996,873)
Adjusted Pre-Tax Operating Income	205,817,378
Adjusted Statutory State Income Tax Rate	7.7775%
Apportionment Factor	0.951996
Effective State Income Tax Rate	7.40410%
Total State Income Tax Expense	(15,238,924)
Federal Taxable Income	179,999,429
Add: Net Operating Loss	-
Add: Special Deductions	1,348,160
Taxable Inc Before NOL & Special Deductions	181,347,589
Add: Ohio Franchise Taxes	-
Less: Other Income and Deductions - Book	(6,373,873)
Less: Non Operating Temporary Differences	4,717,086
Ohio Operating Taxable Income	183,004,376
Adjusted Statutory State Income Tax Rate	7.7775%
Apportionment Factor	0.951996
Effective State Income Tax Rate	7.40410%
Current State Income Tax Expense	(13,549,827)
Deferred State Income Tax Expense	(1,689,097)
2002 Ohio Franchise Tax Accrual	(15,238,924)
2002 Jurisdictional Franchise Tax Accrual	(12,050,607)

Jurisdictional amount provided by Company Witness Roush.

Adjusted Statutory State Franchise Tax Rate[.085*(1-.085)]

Ohio Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

	Ohio Franchise Taxes 2001
Net Operating Income (1998)	287,523,466
Additions:	
Federal Income Taxes	117,082,995
Ohio Franchise Taxes	-
Allowance for Other Funds	104,047
Deductions:	
Net Interest Charges	(77,391,010)
Pre-Tax Operating Income	327,319,498
Less Permanent Differences:	
Deferred Comp Insurance Premium	9,330
Deferred Comp CSV Earnings	(73,808)
Deferred Comp Interest Expense	-
Meals and T&E	169,347
COLI Premium Expense	-
COLI Earnings	(9,927,503)
COLI Death Benefits	(5,695,318)
COLI Interest Expense	5,093,282
Leased Luxury Auto	5,666
Total Permanent Differences	(10,419,004)
Adjusted Pre-Tax Operating Income	316,900,494
Adjusted Statutory State Income Tax Rate	7.7775%
Apportionment Factor	0.734756
Effective State Income Tax Rate	5.71460%
Total State Income Tax Expense	(18,109,596)
Federal Taxable Income	229,717,097
Add: Net Operating Loss	-
Add: Special Deductions	1,964,191
Taxable Inc Before NOL & Special Deductions	231,681,288
Add: Ohio Franchise Taxes	-
Less: Other Income and Deductions - Book	(9,428,744)
Less: Non Operating Temporary Differences	2,382,006
Ohio Operating Taxable Income	238,728,026
Adjusted Statutory State Income Tax Rate	7.7775%
Apportionment Factor	0.734756
Effective State Income Tax Rate	5.71460%
Current State Income Tax Expense	(13,642,352)
First Year Limitation	66.6667%
First Year Current State Income Tax Expense	(9,094,906)
Deferred State Income Tax Expense	(4,467,244)
2001 Ohio Franchise Tax Accrual	(13,562,150)
2001 Jurisdictional Franchise Tax Accrual	(11,760,978)

Jurisdictional amount provided by Company Witness Roush.

Adjusted Statutory State Franchise Tax Rate[.085*(1-.085)]

Ohio Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

	Ohio Franchise Taxes 2002
Net Operating Income (1998)	287,523,466
Additions:	
Federal Income Taxes	117,082,995
Ohio Franchise Taxes	-
Allowance for Other Funds	104,047
Deductions:	
Net Interest Charges	(77,391,010)
Pre-Tax Operating Income	327,319,498
Less Permanent Differences:	
Deferred Comp Insurance Premium	9,330
Deferred Comp CSV Earnings	(73,808)
Deferred Comp Interest Expense	-
Meals and T&E	169,347
COLI Premium Expense	-
COLI Earnings	(9,927,503)
COLI Death Benefits	(5,695,318)
COLI Interest Expense	5,093,282
Leased Luxury Auto	5,666
Total Permanent Differences	(10,419,004)
Adjusted Pre-Tax Operating Income	316,900,494
Adjusted Statutory State Income Tax Rate	7.7775%
Apportionment Factor	0.734756
Effective State Income Tax Rate	5.71460%
Total State Income Tax Expense	(18,109,596)
Federal Taxable Income	229,717,097
Add: Net Operating Loss	-
Add: Special Deductions	1,964,191
Taxable Inc Before NOL & Special Deductions	231,681,288
Add: Ohio Franchise Taxes	-
Less: Other Income and Deductions - Book	(9,428,744)
Less: Non Operating Temporary Differences	2,382,006
Ohio Operating Taxable Income	238,728,026
Adjusted Statutory State Income Tax Rate	7.7775%
Apportionment Factor	0.734756
Effective State Income Tax Rate	5.71460%
Current State Income Tax Expense	(13,642,352)
Deferred State Income Tax Expense	(4,467,244)
2002 Ohio Franchise Tax Accrual	(18,109,596)
2002 Jurisdictional Franchise Tax Accrual	(15,696,730)

Jurisdictional amount provided by Company Witness Roush.

Adjusted Statutory State Franchise Tax Rate[.085*(1-.085)]

Columbus Southern Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

WP EXHIBIT NO. ____ MAP-3

	Property Taxes	
Property Taxes Included In Base Rates	48,812,058	
Less: Revised Property Taxes	32,783,875	
Property Tax Reduction	16,028,183	
Jurisdictional Allocation	96.60%	
Jurisdictional Property Tax Reduction	15,483,225	<==========
Production Property		
Original Plant Taxable Value	207,906,055	
Original Station Equipment Taxable Value	9,275,532	
Original Fuel Stock Taxable Value	18,038,262	
Original M&S Taxable Value	12,647,351	
Original Production Property Taxable Value	247,867,200	
Revised Production Taxable Value	51,976,514	
Revised Station Equipment Taxable Value	8,246,795	
Revised Fuel Stock Taxable Value	5,124,506	
Revised M&S Taxable Value	3,592,998	
Revised Production Property Taxable Value	68,940,813	
Net Decrease in Taxable Value	178,926,387	
Property Tax Rate/$1,000	53.262	
Property Tax - Excluding Zimmer	9,529,977	
Zimmer Property Tax	5,858,073	
Total Company Property Tax	15,388,050	
Jurisdictional Allocation	96.60%	
Jurisdictional Property Tax	14,864,856	
Other Property		
Original General Plant Taxable Value	8,010,183	
Original Future Use Taxable Value	794,641	
Non Utility Property Taxable Value	-	
Original Other Property Taxable Value	8,804,824	
Revised General Plant Taxable Value	2,275,620	
Revised Future Use Taxable Value	225,750	
Revised Non Utility Taxable Value	-	
Revised Production Property Taxable Value	2,501,370	
Net Decrease in Taxable Value	6,303,454	
Property Tax Rate/$1,000	53.262	
Property Tax - Excluding Zimmer	335,735	
Zimmer Property Tax	5,359	
Total Company Property Tax	341,094	
Jurisdictional Allocation	96.60%	
Jurisdictional Property Tax	329,497	
Jurisdictional Property Tax Reduction	15,194,353	
Production Factor	0.978315	
General Factor	0.021685	

Columbus Southern Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

WP EXHIBIT NO. ___ MAP-3
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	(1)	(2)	(3)	(4)	(5)
[redacted]	Total Amount		Total Company	Allocation Percent	Adjusted For Jusidiction
1. Jurisdictional Plant in Service at 03/31/91					
Intangible Plant:			0		0
Steam Production Plant:	1,558,923,000		1,558,923,000	100.0000%	1,558,923,000
Transmission Plant:	274,000,000		274,000,000	100.0000%	274,000,000
Distribution Plant:	662,253,000		662,253,000	100.0000%	662,253,000
General Plant-Excluding A/C 399:	56,722,000		56,722,000	100.0000%	56,722,000
Experimental Plant	1,148,000		1,148,000	100.0000%	1,148,000
Total	2,553,046,000	0	2,553,046,000		2,553,046,000
2. Jurisdictional Fuel Inventory at 03/31/91					
Steam Production Plant:	32,261,700		32,261,700	100.0000%	32,261,700
Other:			0	100.0000%	0
Total	32,261,700	0	32,261,700		32,261,700
3. Jurisdictional Material and Supplies at 03/31/91					
Steam Production:	8,010,397		8,010,397	100.0000%	8,010,397
Other:	0		0	100.0000%	0
Total	8,010,397	0	8,010,397		8,010,397
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Columbus Southern Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

WP EXHIBIT NO. ____ MAP-3

[redacted]	(6) Staff Adjustment	(7) Staff Adjusted Jurisdiction	(8) Zimmer Plant Adjustments	(9) Net of Zimmer Plant
1. Jurisdictional Plant in Service at 03/31/91				
Intangible Plant:		0		0
Steam Production Plant:		1,558,923,000	845,653,000	713,270,000
Transmission Plant:		274,000,000	5,033,000	268,967,000
Distribution Plant:		662,253,000		662,253,000
General Plant-Excluding A/C 399:		56,722,000	285,000	56,437,000
Experimental Plant		1,148,000		1,148,000
Total	0	2,553,046,000	850,971,000	1,702,075,000
2. Jurisdictional Fuel Inventory at 03/31/91				
Steam Production Plant:	0	32,261,700		32,261,700
Other:	0	0		0
Total	0	32,261,700	0	32,261,700
3. Jurisdictional Material and Supplies at 03/31/91				
Steam Production:	0	8,010,397		8,010,397
Other:	0	0		0
Total	0	8,010,397	0	8,010,397
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Columbus Southern Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

WP EXHIBIT NO. ___ MAP-3
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[redacted]	(9) Net of West Virginia	(10) Assessment Valuation Percentage	(11) Property Tax Value	(12) Ohio Property Tax Rate/1000	(13) Ohio Property Tax
1. Jurisdictional Plant in Service at 03/31/91					
Intangible Plant:	0	40.3096%	0	53.262	0
Steam Production Plant:	713,270,000	40.3096%	287,516,284	53.262	15,313,692
Transmission Plant:	268,967,000	40.3096%	108,419,522	53.262	5,774,641
Distribution Plant:	662,253,000	40.3096%	266,951,535	53.262	14,218,373
General Plant-Excluding A/C 399:	56,437,000	40.3096%	22,749,529	53.262	1,211,685
General Plant-A/C 399	1,148,000	40.3096%	462,754	53.262	24,647
Total	1,702,075,000		686,099,624		36,543,038
2. Jurisdictional Fuel Inventory at 03/31/91					
Steam Production Plant:	32,261,700	40.3096%	13,004,562	53.262	692,649
Other:	0	40.3096%	0	53.262	0
Total	32,261,700		13,004,562		692,649
3. Jurisdictional Material and Supplies at 03/31/91					
Steam Production:	8,010,397	40.3096%	3,228,959	53.262	171,981
Other:	0	40.3096%	0	53.262	0
Total	8,010,397		3,228,959		171,981
4. Property Subject to Tax	1,742,347,097		702,333,145		37,407,668

Columbus Southern Power Company
Electric Transition Plan
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[redacted]	(14) Impact of Unknown Passed Levies	(15) Zimmer Plant	(16) Total Company Property Tax	(17) Jurisdictional Allocation	(18) Jurisdictional Property Tax
1. Jurisdictional Plant in Service at 03/31/91					
Intangible Plant:	3,458,390		3,458,390	96.60%	3,340,805
Steam Production Plant:		7,626,407	22,940,099	96.60%	22,160,136
Transmission Plant:			5,774,641	96.60%	5,578,303
Distribution Plant:			14,218,373	96.60%	13,734,948
General Plant-Excluding A/C 399:		7,485	1,219,170	96.60%	1,177,719
General Plant-A/C 399			24,647	96.60%	23,809
Total	3,458,390	7,633,892	47,635,320		46,015,720
2. Jurisdictional Fuel Inventory at 03/31/91					
Steam Production Plant:		187,967	880,616	96.60%	850,675
Other:			0	96.60%	0
Total	0	187,967	880,616		850,675
3. Jurisdictional Material and Supplies at 03/31/91					
Steam Production:		124,141	296,122	96.60%	286,054
Other:			0	96.60%	0
Total	0	124,141	296,122		286,054
4. Property Subject to Tax	3,458,390	7,946,000	48,812,058		47,152,449

Columbus Southern Power Company
Electric Transition Plan
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Assessed Value 1990 property as of 12/31/89	681,389,680	***************
Taxable Personal Property	631,995,080	
Taxable Real Property	43,292,000	
Unknown Property	6,102,600	
Original Cost 12/31/89	1,690,392,203	***************
Plant original cost	1,616,581,958	
Fuel Cost	20,498,025	
M & S	20,483,907	
Plant held for future use	14,708,630	
Experimental Plant	811,320	
Non Utility Plant	17,308,363	
Percentage Assessed		40.3096%

Columbus Southern Power Company
Electric Transition Plan
Case No. 99-__-EL-ETP

[redacted]	(1) Total Amount	(2)	(3) Total Company	(4) Allocation Percent	(5) Adjusted For Jusidiction	(6) Staff Adjustment
1. Jurisdictional Plant in Service at 03/31/91						
Intangible Plant:			0		0	
Steam Production Plant:	1558923000		1558923000	100.0000%	1558923000	
Transmission Plant:	274000000		274000000	100.0000%	274000000	
Distribution Plant:	662253000		662253000	100.0000%	662253000	
General Plant-Excluding A/C 399:	56722000		56722000	100.0000%	56722000	
Experimental Plant	1148000		1148000	100.0000%	1148000	
Total	2553046000	0	2553046000		2553046000	0
2. Jurisdictional Fuel Inventory at 03/31/91						
Steam Production Plant:	32261700		32261700	100.0000%	32261700	0
Other:			0	100.0000%	0	0
Total	32261700	0	32261700		32261700	0
3. Jurisdictional Material and Supplies at 03/31/91						
Steam Production:	8010397		8010397	100.0000%	8010397	0
Other:	0		0	100.0000%	0	0
Total	8010397	0	8010397		8010397	0

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Columbus Southern Power Company
Electric Transition Plan
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[redacted]	(7) Staff Adjusted Jurisdiction	(8) Zimmer Plant Adjustments	(9) Net of Zimmer Plant
1. Jurisdictional Plant in Service at 03/31/91			
Intangible Plant:	0		0
Steam Production Plant:	1558923000	845653000	713270000
Transmission Plant:	274000000	5033000	268967000
Distribution Plant:	662253000		662253000
General Plant-Excluding A/C 399:	56722000	285000	56437000
Experimental Plant	1148000		1148000
	----------------	----------------	----------------
Total	2553046000	850971000	1702075000
2. Jurisdictional Fuel Inventory at 03/31/91			
Steam Production Plant:	32261700		32261700
Other:	0		0
	----------------	----------------	----------------
Total	32261700	0	32261700
3. Jurisdictional Material and Supplies at 03/31/91			
Steam Production:	8010397		8010397
Other:	0		0
	----------------	----------------	----------------
Total	8010397	0	8010397
xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx	xxxxxxxxxxx	xxxxxxxxxxxx	xxxxxxxxxxx

Columbus Southern Power Company
Electric Transition Plan
Case No. 99-__-EL-ETP

[redacted]	(9) Net of West Virginia	(10) Assessment Valuation Percentage	(11) Property Tax Value	(12) Ohio Property Tax Rate/1000	(13) Ohio Property Tax	(14) Impact of Unknown Passed Levies
1. Jurisdictional Plant in Service at 03/31/91						
Intangible Plant:	0	29.3518%	0	53.262	0	3458390
Steam Production Plant:	713270000	29.3518%	209357584	53.262	11150803.64	
Transmission Plant:	268967000	29.3518%	78946656	53.262	4204856.792	
Distribution Plant:	662253000	29.3518%	194383176	53.262	10353236.72	
General Plant-Excluding A/C 399:	56437000	29.3518%	16565275	53.262	882299.6771	
General Plant-A/C 399	1148000	29.3518%	336959	53.262	17947.11026	
Total	1702075000		499589650		26609143.94	3458390
2. Jurisdictional Fuel Inventory at 03/31/91						
Steam Production Plant:	32261700	29.3518%	9469390	53.262	504358.6502	
Other:	0	29.3518%	0	53.262	0	
Total	32261700		9469390		504358.6502	0
3. Jurisdictional Material and Supplies at 03/31/91						
Steam Production:	8010397	29.3518%	2351196	53.262	125229.4014	
Other:	0	29.3518%	0	53.262	0	
Total	8010397		2351196		125229.4014	0
4. Property Subject to Tax	1742347097		511410236		27238731.99	3458390

Columbus Southern Power Company
Electric Transition Plan
Case No. 99-__-EL-ETP

[redacted]	(15) Zimmer Plant	(16) Total Company Property Tax	(17) Jurisdictional Allocation	(18) Jurisdictional Property Tax
1. Jurisdictional Plant in Service at 03/31/91				
Intangible Plant:		3458390	96.60%	3340805
Steam Production Plant:	1991413	13142216.64	96.60%	12695381
Transmission Plant:		4204856.792	96.60%	4061892
Distribution Plant:		10353236.72	96.60%	10001227
General Plant-Excluding A/C 399:	2126	884425.6771	96.60%	854355
General Plant-A/C 399		17947.11026	96.60%	17337
	----------	----------		----------
Total	1993539	32061072.94		30970997
2. Jurisdictional Fuel Inventory at 03/31/91				
Steam Production Plant:	53400	557758.6502	96.60%	538795
Other:		0	96.60%	0
	----------	----------		----------
Total	53400	557758.6502		538795
3. Jurisdictional Material and Supplies at 03/31/91				
Steam Production:	35267	160496.4014	96.60%	155040
Other:		0	96.60%	0
	----------	----------		----------
Total	35267	160496.4014		155040
4. Property Subject to Tax	2082206	32779327.99		31664832

Columbus Southern Power Company
Electric Transition Plan
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Assessed Value 1990 property as of 12/31/89	496159834.9	
Personal Property	446765234.9	
Real Property	43292000	
Unknown Property	6102600	
Original Cost in 12/31/89	1690392203	
Percent Assessed		29.3518%

As of 12/31/89	(10a) Original Assessment True Tax Value	(10b) Taxable Value	(10c) New Law Taxable Value	ZIMMER	Taxable Value
Production Plant	207906055	207906055	51976514	WPC 3.09e(u1	242936313
Station Equipment	9275532	9275532	8246795		1841229
Transmission Plant	49855795	43873099.6	43873099.6		0
Station Equipment	45011120	39609785.6	39609785.6		
Distribution Equipment	297240736	261571847.7	261571847.7		
Station Equipment	28283900	24889832	24889832		
General Plant	9102481	8010183.28	2275620		141165
Fuel Stock	20498025	18038262	5124506		3428000
M & S - Plant	14371990	12647351.2	3592998		2264000
M & S - Other	6111917	5378486.96	5378487	Fuel Adjustme	-265000
Plant held for Future Use	903001	794640.88	225750	M & S Adj	-231000
Non utility Property		0	0		
Total	688560552	631995076.2	446765234.9		250114707

Columbus Southern Power Company
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Assessed Value 1990 property as of 12/31/89
Personal Property
Real Property
Unknown Property
Original Cost in 12/31/89
Percent Assessed

As of 12/31/89	Depreciation Rate	Taxable Property	Assessment Ratio	Assessed Value	Effective Tax Rate	Taxes Paid
Production Plant	50.00%	121468157	100.00%	121468157	0.06231	7568681
Station Equipment	50.00%	920615	100.00%	920615	0.06231	57364
Transmission Plant	98.30%	0	88.00%	0	0.06231	0
Station Equipment						0
Distribution Equipment						0
Station Equipment						0
General Plant	96.70%	136507	88.00%	120126	0.06231	7485
Fuel Stock	100.00%	3428000	88.00%	3016640	0.06231	187967
M & S - Plant	100.00%	2264000	88.00%	1992320	0.06231	124141
M & S - Other	100.00%	0	88.00%	0	0.06231	0
Plant held for Future Use	100.00%	0	88.00%	0	0.06231	0
Non utility Property						
Total		128217279		127517858		7945638
		Real Property		24195000		

Columbus Southern Power Company
Electric Transition Plan
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Assessed Value 1990 property as of 12/31/89
Personal Property
Real Property
Unknown Property
Original Cost in 12/31/89
Percent Assessed

As of 12/31/89	New Law Taxable Value	Effective Tax Rate	Estimated Taxes Paid
Production Plant	30367039	0.06231	1892170
Station Equipment	1592737	0.06231	99243
Transmission Plant	0	0.06231	0
Station Equipment		0.06231	
Distribution Equipment		0.06231	
Station Equipment		0.06231	
General Plant	34127	0.06231	2126
Fuel Stock	857000	0.06231	53400
M & S - Plant	566000	0.06231	35267
M & S - Other	0	0.06231	0
Plant held for Future Use	0	0.06231	0
Non utility Property			
Total	33416903		2082206

Note for Production Station Equipment-New Taxable	18551065
302 Calculation	50.52%
	0.4997
True Tax Value	9371358
	88%
Taxable Value	8246795
Total M & S	20483907
M & S - Other	6111917
M & S - Plant	14371990

Ohio Power Company
Electric Transition Plan
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	Property Taxes
Property Taxes Included In Base Rates	60,675,278
Less: Revised Property Taxes	40,362,631
Jurisdictional Property Tax Reduction	20,312,647
Production Property	
Original Plant Taxable Value	426,534,053
Original Station Equipment Taxable Value	14,752,312
Original Fuel Stock Taxable Value	125,572,190
Original M&S Taxable Value	11,532,807
Original Production Property Taxable Value	578,391,362
Revised Production Taxable Value	106,633,513
Revised Station Equipment Taxable Value	13,170,622
Revised Fuel Stock Taxable Value	35,673,918
Revised M&S Taxable Value	3,276,366
Revised Production Property Taxable Value	158,754,419
Net Decrease in Taxable Value	419,636,943
Property Tax Rate/$1,000	51.870
Property Tax - Excluding Zimmer	21,766,568
Zimmer Property Tax	-
Total Company Property Tax	21,766,568
Jurisdictional Allocation	90.90%
Jurisdictional Property Tax	19,785,810
Other Property	
Original General Plant Taxable Value	13,721,341
Original Future Use Taxable Value	494,373
Non Utility Property Taxable Value	123,442
Original Other Property Taxable Value	14,339,156
Revised General Plant Taxable Value	3,898,108
Revised Future Use Taxable Value	140,447
Revised Non Utility Taxable Value	35,069
Revised Production Property Taxable Value	4,073,624
Net Decrease in Taxable Value	10,265,532
Property Tax Rate/$1,000	51.870
Property Tax - Excluding Zimmer	532,473
Zimmer Property Tax	5,359
Total Company Property Tax	537,832
Jurisdictional Allocation	94.17%
Jurisdictional Property Tax	506,476
Jurisdictional Property Tax Reduction	20,292,286
Production Factor	0.975041
General Factor	0.024959

Ohio Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

	(1)	(2)	(3)	(4)	(5)
[redacted]	Total Amount	R & O Exclusion	Total Company	Allocation Percent	Adjusted For Jusidiction
1. Jurisdictional Plant in Service at 6/30/94					
Intangible Plant:	72,000	0	72,000	91.6667%	66,000
Steam Production Plant:	2,453,514,000	258,159,000	2,195,355,000	90.9000%	1,995,577,695
Transmission Plant:	787,991,000	12,600,000	775,391,000	91.9200%	712,739,407
Distribution Plant:	778,545,000	361,000	778,184,000	99.8589%	777,085,982
General Plant-Excluding A/C 399:	83,467,000	220,000	83,247,000	94.1700%	78,393,700
General Plant-A/C 399	14,195,000	3,815,000	10,380,000	90.9000%	9,435,420
Total	4,117,784,000	275,155,000	3,842,629,000		3,573,298,204
2. Jurisdictional Fuel Inventory at 6/30/94					
Steam Production Plant:	65,154,445		65,154,445	100.0000%	65,154,445
Other:			0	100.0000%	0
Total	65,154,445	0	65,154,445		65,154,445
3. Jurisdictional Material and Supplies at 6/30/94					
Steam Production:	15,512,372		15,512,372	100.0000%	15,512,372
Other:	0		0	100.0000%	0
Total	15,512,372	0	15,512,372		15,512,372

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Ohio Power Company
Electric Transition Plan
Case No. 99-__-EL-ETP

[redacted]	(6) Staff Adjustment	(7) Staff Adjusted Jurisdiction	(8) West Virginia Adjustments	(9) Net of West Virginia
1. Jurisdictional Plant in Service at 6/30/94				
Intangible Plant:		66,000		66,000
Steam Production Plant:	-54,000	1,995,523,695	837,769,426	1,157,754,269
Transmission Plant:		712,739,407		712,739,407
Distribution Plant:	-394,000	776,691,982		776,691,982
General Plant-Excluding A/C 399:	-1,685,000	76,708,700		76,708,700
General Plant-A/C 399	-795,000	8,640,420		8,640,420
Total	-2,928,000	3,570,370,204	837,769,426	2,732,600,778
2. Jurisdictional Fuel Inventory at 6/30/94				
Steam Production Plant:	0	65,154,445		65,154,445
Other:	0	0		0
Total	0	65,154,445	0	65,154,445
3. Jurisdictional Material and Supplies at 6/30/94				
Steam Production:	0	15,512,372		15,512,372
Other:	0	0		0
Total	0	15,512,372	0	15,512,372

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Ohio Power Company
Electric Transition Plan
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[redacted]	(9) Net of West Virginia	(10) Assessment Valuation Percentage	(11) Property Tax Value	(12) Ohio Property Tax Rate/1000	(13) Ohio Property Tax
1. Jurisdictional Plant in Service at 6/30/94					
Intangible Plant:	66,000	41.58%	27,443	51.87	1,423
Steam Production Plant:	1,157,754,269	41.58%	481,394,225	51.87	24,969,918
Transmission Plant:	712,739,407	41.58%	296,357,045	51.87	15,372,040
Distribution Plant:	776,691,982	41.58%	322,948,526	51.87	16,751,340
General Plant-Excluding A/C 399:	76,708,700	41.58%	31,895,477	51.87	1,654,418
General Plant-A/C 399	8,640,420	41.58%	3,592,687	51.87	186,353
Total	2,732,600,778		1,136,215,403		58,935,493
2. Jurisdictional Fuel Inventory at 6/30/94					
Steam Production Plant:	65,154,445	41.58%	27,091,218	51.87	1,405,221
Other:	0	41.58%	0	51.87	0
Total	65,154,445		27,091,218		1,405,221
3. Jurisdictional Material and Supplies at 6/30/94					
Steam Production:	15,512,372	41.58%	6,450,044	51.87	334,564
Other:	0	41.58%	0	51.87	0
Total	15,512,372		6,450,044		334,564
4. Property Subject to Tax	2,813,267,595		1,169,756,665		60,675,278

Ohio Power Company
Electric Transition Plan
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		Assessed		Assessed	
Assessed Value 1993 property as of 12/31/92	1,283,781,360	Personal	1,197,554,600	Real	86,226,760
Original Cost 12/31/92-Ohio Only	3,087,186,143				
Percent assessed		41.58%			

Original Cost	Fuel Cost	M & S	Tidd Plant	Schedule E
2,864,180,107	142,695,670	25,202,813	54,046,662	1,060,891

Ohio Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

WP EXHIBIT NO. ___ MAP-3

	(1)	(2)	(3)	(4)	(5)	(6)
[redacted]	Total Amount	R & O Exclusion	Total Company	Allocation Percent	Adjusted For Jusidiction	Staff Adjustment
1. Jurisdictional Plant in Service at 6/30/94						
Intangible Plant:	72000	0	72000	91.6667%	66000	
Steam Production Plant:	2453514000	258159000	2195355000	90.9000%	1995577695	-54000
Transmission Plant:	787991000	12600000	775391000	91.9200%	712739407	
Distribution Plant:	778545000	361000	778184000	99.8589%	777085982	-394000
General Plant-Excluding A/C 399:	83467000	220000	83247000	94.1700%	78393700	-1685000
General Plant-A/C 399	14195000	3815000	10380000	90.9000%	9435420	-795000
Total	4117784000	275155000	3842629000		3573298204	-2928000
2. Jurisdictional Fuel Inventory at 6/30/94						
Steam Production Plant:	65154445		65154445	100.0000%	65154445	0
Other:			0	100.0000%	0	0
Total	65154445	0	65154445		65154445	0
3. Jurisdictional Material and Supplies at 6/30/94						
Steam Production:	15512372		15512372	100.0000%	15512372	0
Other:	0		0	100.0000%	0	0
Total	15512372	0	15512372		15512372	0
xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx	XXXXXXXXXX	XXXXXXXXXXX	XXXXXXXXXX	XXXXXXXXXX	XXXXXXXXXX	XXXXXXXXXXX

Ohio Power Company
Electric Transition Plan
Case No. 99-__-EL-ETP

WP EXHIBIT NO. __ MAP-3

	(7)	(8)	(9)
[redacted]	Staff Adjusted Jurisdiction	West Virginia Adjustments	Net of West Virginia
1. Jurisdictional Plant in Service at 6/30/94			
Intangible Plant:	66000		66000
Steam Production Plant:	1995523695	837769426	1157754269
Transmission Plant:	712739407		712739407
Distribution Plant:	776691982		776691982
General Plant-Excluding A/C 399:	76708700		76708700
General Plant-A/C 399	8640420		8640420
Total	3570370204	837769426	2732600778
2. Jurisdictional Fuel Inventory at 6/30/94			
Steam Production Plant:	65154445		65154445
Other:	0		0
Total	65154445	0	65154445
3. Jurisdictional Material and Supplies at 6/30/94			
Steam Production:	15512372		15512372
Other:	0		0
Total	15512372	0	15512372

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Ohio Power Company
Electric Transition Plan
Case No. 99-__-EL-ETP

WP EXHIBIT NO. __ MAP-3

[illegible]	(9) Net of West Virginia	(10) Assessment Valuation Percentage	(11) Property Tax Value	(12) Ohio Property Tax Rate/1000	(13) Ohio Property Tax
1. Jurisdictional Plant in Service at 6/30/94					
Intangible Plant:	66000	27.66%	18256	51.87	946.93872
Steam Production Plant:	1157754269	27.66%	320234831	51.87	16610580.68
Transmission Plant:	712739407	27.66%	197143720	51.87	10225844.76
Distribution Plant:	776691982	27.66%	214833002	51.87	11143387.81
General Plant-Excluding A/C 399:	76708700	27.66%	21217626	51.87	1100558.261
General Plant-A/C 399	8640420	27.66%	2389940	51.87	123966.1878
	----------------		----------------		----------------
Total	2732600778		755837375		39205284.64
2. Jurisdictional Fuel Inventory at 6/30/94					
Steam Production Plant:	65154445	27.66%	18021719	51.87	934786.5645
Other:	0	27.66%	0	51.87	0
	----------------		----------------		----------------
Total	65154445		18021719		934786.5645
3. Jurisdictional Material and Supplies at 6/30/94					
Steam Production:	15512372	27.66%	4290722	51.87	222559.7501
Other:	0	27.66%	0	51.87	0
	----------------		----------------		----------------
Total	15512372		4290722		222559.7501
4. Property Subject to Tax	2813267595		778149816		40362630.96

Ohio Power Company
Electric Transition Plan
Case No. 99-__-EL-ETP

		Assessed		Assessed	
Assessed Value 1993 property as of 12/31/92	853878878.7	Personal	767652118.7	Real	86226760
Original Cost 12/31/92-Ohio Only	3087186143				
Percent assessed		27.66%			
	Original Cost	Fuel Cost	M & S	Tidd Plant	Schedule E
	2864180107	142695670	25202813	54046662	1060891

	(10a)	(10b)	(10c)
	Original Assessment		New Law
	True Tax Value	Taxable Value	Taxable Value
Production Plant	426534053	426534053	106633513
Station Equipment	14752312	14752312	13170622
Transmission Plant	130680046	114998440.5	114998440.5
Station Equipment	113115582	99541712.16	99541712.16
Distribution Equipment	393783357	346529354.2	346529354.2
Station Equipment	37623751	33108900.88	33108900.88
General Plant	15592433	13721341.04	3898108
Fuel Stock	142695670	125572189.6	35673918
M & S - Plant	13105463	11532807.44	3276366
M & S - Other	12097350	10645668	10645668
Plant held for Future Use	561787	494372.56	140447
Non utility Property	140275	123442	35069
Total	1300682079	1197554593	767652118.7

Ohio Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

Note for Production Station Equipment-New Taxable	29504623	
302 Calculation	50.73%	
	0.4997	
True Tax Value	14966616	
	88%	

Taxable Value	13170622	
M & S Total	25202813	
% T & D	48%	(1998)

M & S - Other	12097350	
M & S - Plant	13105463	

Columbus Southern Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

Municipal Income Tax Rate
1998 Actual

Weighted Payroll Withholding Rate	1.8549%
Weighted Sales Rate	1.8990%
Weighted Property Rate	1.9092%
Subtotal	5.6631%
	3
Weighted Average Municipal Income Tax Rate	1.8877%

Apportionment Factors	
Taxable Municipal Payroll	52,295,532
Total Payroll	84,130,316
Payroll Percentage	0.62160
Payroll Weighting	0.33333
Payroll Factor	0.207199
Municipal Beginning Property	800,070,272
Municipal Ending Property	800,070,272
Average Ohio Property	800,070,272
Ohio Rent Expense	6,176,562
Rent Expense Multiplier	8
Ohio Rental Property	49,412,492
Ohio Property	849,482,764
Beginning Property	2,923,729,014
Ending Property	2,931,504,588
Average Property	2,927,616,801
Rent Expense	12,353,123
Rent Expense Multiplier	8
Rental Property	98,824,984
Total Property	3,026,441,785
Property Percentage	0.280687
Property Weighting	0.33333
Property Factor	0.093561
Ohio Sales	736,726,693
Total Sales	1,187,746,000
Sales Percentage	0.62027
Sales Weighting	0.33333
Sales Factor	0.206756
Ohio Apportionment Factor	0.507516

Ohio Power Company
Electric Transiton Plan
Case No. 99-___-EL-ETP

Municipal Income Tax Rate
1998 Actual

Weighted Payroll Withholding Rate	1.4381%
Weighted Sales Rate	1.4827%
Weighted Property Rate	1.5169%
Subtotal	4.4377%
	3
Weighted Average Municipal Income Tax Rate	1.4792%

Apportionment Factors	
Taxable Municipal Payroll	49,194,448
Total Payroll	157,218,961
Payroll Percentage	0.31290
Payroll Weighting	0.25
Payroll Factor	0.078226
Municipal Beginning Property	474,994,677
Municipal Ending Property	474,994,677
Average Ohio Property	474,994,677
Ohio Rent Expense	7,218,675
Rent Expense Multiplier	8
Ohio Rental Property	57,749,400
Ohio Property	532,744,077
Beginning Property	4,658,153,723
Ending Property	4,697,008,601
Average Property	4,677,581,162
Rent Expense	25,191,470
Rent Expense Multiplier	8
Rental Property	201,531,760
Total Property	4,879,112,922
Property Percentage	0.109189
Property Weighting	0.25
Property Factor	0.027297
Municipal Sales - Taxing Municipalities	563,890,879
Total Sales	2,115,000,000
Sales Percentage	0.26662
Sales Weighting	0.50
Sales Factor	0.133308
Ohio Apportionment Factor	0.238831

Columbus Southern Power Company
Electric Transition Plan
Case No. 99-__-EL-ETP

Operating Taxable Income - 1988	Federal Tax Return	NonOperating Income	NonOperating Book/Tax Differences	Operating Taxable Income
Gross receipts/sales	1,158,514,197	-	1,268,368	1,157,245,829
Cost of operations	531,756,959	-		531,756,959
Gross profit	626,757,238	-	1,268,368	625,488,870
Dividends	1,360,200	60,200	1,300,000	-
Interest	583,639	583,639		-
Gross rents	34,774,111	620,231		34,153,880
Gross royalties	134,199			134,199
Capital gain net income	(72,926)	-		(72,926)
Net gain or (loss) from Form 4797	(6,188,350)	932,363		(7,120,713)
Other income	648,986	1,249,714	(779,695)	178,967
Total Income	657,997,097	3,446,147	1,788,673	652,762,277
Salaries and wages	84,130,316	-		84,130,316
Repairs and maintenance	67,261,032	-		67,261,032
Bad debts	12,827,377			12,827,377
Rents	12,353,123			12,353,123
Taxes and licenses	112,420,477	233,766		112,186,711
Interest	87,612,100			87,612,100
Charitable contributions	506,349	507,919	(1,570)	-
Depreciation	83,755,971		(41,388)	83,797,359
Depletion	20,130			20,130
Advertising	-			-
Pension plans	(547,930)			(547,930)
Employee benefit programs	-			-
Other deductions	16,310,563	9,078,335	(2,885,455)	10,117,683
Total deductions	476,649,508	9,820,020	(2,928,413)	469,757,901
Taxable income before net operating loss and special deductions	181,347,589	(6,373,873)	4,717,086	183,004,376
Net operating loss				-
Special deductions	1,348,160		1,348,160	-
Taxable Income	179,999,429	(6,373,873)	3,368,926	183,004,376

Columbus Southern Power Company
Electric Transition Plan
Case No. 99-___-EL-ETP

Apportionment Factors	**Ohio Franchise Tax**
Ohio Payroll	84,130,316
Total Payroll	84,130,316
Payroll Percentage	1.00000
Payroll Weighting	0.2
Payroll Factor	0.200000
Ohio Beginning Property	2,918,037,115
Ohio Ending Property	2,928,910,962
Average Ohio Property	2,923,474,039
Ohio Rent Expense	12,353,123
Rent Expense Multiplier	8
Ohio Rental Property	98,824,984
Ohio Property	3,022,299,023
Beginning Property	2,923,729,014
Ending Property	2,931,504,588
Average Property	2,927,616,801
Rent Expense	12,353,123
Rent Expense Multiplier	8
Rental Property	98,824,984
Total Property	3,026,441,785
Property Percentage	0.998631
Property Weighting	0.2
Property Factor	0.199726
Ohio Sales	1,093,261,000
Total Sales	1,187,746,000
Sales Percentage	0.92045
Sales Weighting	0.6
Sales Factor	0.552270
Ohio Apportionment Factor	0.951996

Ohio Power Company
Electric Transition Plan
Case No. 99-__-EL-ETP

WP EXHIBIT NO. _____ MAP-5

Operating Taxable Income - 1998	Federal Tax Return	NonOperating Income	NonOperating Book/Tax Differences	Operating Taxable Income
Gross receipts/sales	2,105,121,554	-		2,105,121,554
Cost of operations	1,035,345,678	-	35,963	1,035,309,715
Gross profit	1,069,775,876	-	(35,963)	1,069,811,839
Dividends	1,777,129		1,777,129	-
Interest	1,208,378	1,208,378		-
Gross rents	12,581,903	2,637,382		9,944,521
Gross royalties	184,674	184,674		-
Capital gain net income	2,002,306	2,002,306		-
Net gain or (loss) from Form 4797	(3,153,921)	163,753		(3,317,674)
Other income	2,089,142	2,235,116	(1,881,176)	1,735,202
Total Income	1,086,465,487	8,431,609	(140,010)	1,078,173,888
Salaries and wages	157,218,961			157,218,961
Repairs and maintenance	151,520,030			151,520,030
Bad debts	10,329,247			10,329,247
Rents	25,191,470	2,164,211		23,027,259
Taxes and licenses	169,929,547	663,444		169,266,103
Interest	143,769,732			143,769,732
Charitable contributions	711,169	711,169		-
Depreciation	111,050,615		2,016,000	109,034,615
Depletion	28,005		27,665	340
Advertising	-			-
Pension plans	(60,448)			(60,448)
Employee benefit programs	-			-
Other deductions	85,095,871	14,321,529	(4,565,681)	75,340,023
Total deductions	854,784,199	17,860,353	(2,522,016)	839,445,862
Taxable income before net operating loss and special deductions	231,681,288	(9,428,744)	2,382,006	238,728,026
Net operating loss				-
Special deductions	1,964,191		1,964,191	-
Taxable Income	229,717,097	(9,428,744)	417,815	238,728,026

Ohio Power Company
Electric Transiton Plan
Case No. 99-___-EL-ETP

	Ohio Franchise Tax
Apportionment Factors	
Ohio Payroll	131,208,843
Total Payroll	157,218,961
Payroll Percentage	0.83456
Payroll Weighting	0.2
Payroll Factor	0.166912
Ohio Beginning Property	3,376,461,767
Ohio Ending Property	3,408,229,662
Average Ohio Property	3,392,345,715
Ohio Rent Expense	14,437,350
Rent Expense Multiplier	8
Ohio Rental Property	115,498,800
Ohio Property	3,507,844,515
Beginning Property	4,658,153,723
Ending Property	4,697,008,601
Average Property	4,677,581,162
Rent Expense	25,191,470
Rent Expense Multiplier	8
Rental Property	201,531,760
Total Property	4,879,112,922
Property Percentage	0.718951
Property Weighting	0.2
Property Factor	0.143790
Ohio Sales	1,494,792,000
Total Sales	2,115,000,000
Sales Percentage	0.70676
Sales Weighting	0.6
Sales Factor	0.424054
Ohio Apportionment Factor	0.734756

EXHIBIT NO.________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP
In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP

DIRECT TESTIMONY OF
DAVID M. ROUSH
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

INDEX TO DIRECT TESTIMONY OF
DAVID M. ROUSH
PUCO CASE NOS. 99-___-EL-ETP and
99-___-EL-ETP

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
DAVID M. ROUSH
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
CASE NO. 99-___-EL-ETP
AND
OHIO POWER COMPANY
CASE NO. 99-___-EL-ETP

Personal Data

Q. Please state your name and business address.

A. My name is David M. Roush. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. Please indicate by whom you are employed and in what capacity.

A. I am employed as a Regulatory Consultant I in the Energy Pricing and Regulatory Services Department for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP), the parent of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCO).

Q. Please briefly describe your educational background and business experience.

I graduated from The Ohio State University in 1989 with a Bachelor of Science degree in mathematics with a computer and information science minor. In 1999 I earned a Master of Business Administration degree from The University of Dayton. I have completed both the EEI Electric Rate Fundamentals and Advanced Courses.

In 1989 I joined AEPSC as a Rate Assistant. Since that time I have progressed through various positions and was promoted to my current position of Regulatory Consultant I in April 1998. My responsibilities include the preparation of cost-of-service and rate design for the AEP System operating companies, and the preparation of special contracts and pricing for retail customers. I have submitted testimony before the Public Service Commission of West Virginia.

Purpose of Testimony

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

A. The purpose of my testimony is to sponsor portions of Part A of the Companies' filings.

Q. What portions of Part A do you sponsor?

A. I sponsor the revenue summaries, cost-of-service studies and typical bill comparisons as contained in Schedules UNB-3, UNB-4, UNB-5, UNB-6, UNB-7 and UNB-8, including those designated as .1, .1ADJ and .2.

Schedule UNB-3

Q. Please describe Schedules UNB-3 and UNB-3.1.

A. Schedules UNB-3 and UNB-3.1 are simply a restatement of the billing determinants, rates and revenues as provided by the Companies for revenue verification purposes at the conclusion of their last rate proceedings. For CSP, the schedules are based upon the Commission's January 13, 1994 entry on remand in Case No. 94-418-EL-AIR. For OPCO, the schedules are based upon the

Commission's March 23, 1995 order approving the Stipulation in Case No. 94-996-EL-AIR.

Q. Were any changes to this data made in the Companies' Schedule UNB-3 and UNB-3.1?

A. Yes. For both companies, the schedules were updated to reflect the EFC and PIPP rates in effect on October 4, 1999. For OPCO, the difference between the billing determinants and the metered energy used for calculating PIPP and EFC was removed. In OPCO's last case, forecasted billing units were reduced to reflect the effects of DSM programs. This adjustment was not made in the billing units for EFC and PIPP in order to maintain the synchronization between revenues and the test year expense levels. Since the Companies' unbundled rates are calculated using revenues excluding the test year levels of EFC and PIPP, maintaining this difference is no longer necessary. Therefore, the schedules for OPCO now reflect the same basis for all billing determinants.

Q. Please describe Schedules UNB-3.1ADJ and UNB-3.2.

A. Schedule UNB-3.1ADJ is a narrative description of all changes, additions or deletions to the Companies' rate schedules since the last rate proceeding. Schedule UNB-3.2 provides current billing determinants and revenues for special contracts and the new interruptible service rate schedules not included in each Company's last rate case. All billing determinants included in Schedule UNB-3.2 are for the twelve months ended September, 1999. The totals reflected in Schedule UNB-3 do not include the effects of Schedule UNB-3.2.

Schedule UNB-4

Q. Please describe Schedule UNB-4.

A. For each Company, Schedule UNB-4 is based upon the cost-of-service study as filed in its last rate case. For CSP, Schedule UNB-4 was adjusted to comply with the Commission's orders and entry on remand in Case No. 91-418-EL-AIR. For OPCO, Schedule UNB-4 was adjusted to reflect the Commission's order approving the stipulation in Case No. 94-996-EL-AIR. Detail showing the derivation of the generation, transmission and distribution components for each class was added for both Companies. This information is required for the development of unbundled rates in Schedule UNB-5.

Q. Were any changes made in the functionalization, classification and allocation of costs in Schedule UNB-4?

A. No. Schedule UNB-4 reflects changes to rate base, expenses and authorized rate of return ordered by the Commission in each Company's last rate case. Schedule UNB-4 also reflects the class revenue levels, as approved by the Commission, developed according to the methodology as described in the testimony of Company Witness Thomas. No other changes were made.

Q. How were the revenues for the special contracts and new rate schedules as shown in Schedule UNB-3.2 functionalized?

A. The Companies' new interruptible schedules were originally designed based upon each Company's GS-4 rate schedule. Therefore, the demand-related generation component of the GS-4 rate was discounted to derive the interruptible rates in the same way that the interruptible rates in the last case were designed. As such, the functionalization of the GS-4 schedule as derived in Schedule UNB-4 should be used to functionalize the new interruptible schedules. The interruptible discount is merely a reduction to the Schedule GS-4 generation component. Similarly, Schedule GS-4 was the basis for functionalizing the special contracts.

Schedule UNB-5

Q. Please describe Schedule UNB-5.

A. Schedule UNB-5 shows the unbundling of the Companies' current rates into generation, transmission, distribution and regulatory asset components. These unbundled rates are based upon the functionalized base revenue shown in Schedule UNB-4. The Companies' rates and charges for each schedule and special contract were unbundled in a manner consistent with Am. Sub. S. B. No. 3 and the Companies' unbundling methodology as discussed by Company Witness Thomas. Except for very minor differences due to rounding, the unbundled rates in Schedule UNB-5 produce revenues equivalent to those shown in Schedule UNB-3.

Schedule UNB-6

Q. Please describe Schedule UNB-6.

A. Schedule UNB-6 summarizes all of the adjustments to the Companies' unbundled rates resulting from Am. Sub. S. B. No. 3. These adjustments included the addition of several new riders, surcharges and credits as discussed by Company Witnesses Forrester and Thomas.

The first line of Schedule UNB-6 reflects the functionalization of revenue as shown in Schedule UNB-4, adjusted for the changes in EFC and PIPP and the separation of regulatory assets and ancillary services from all other generation-related revenues. Line 10 of Schedule UNB-6 reflects anticipated test-year revenues resulting from all adjustments to the unbundled rates with the exception of the residential discount shown on Line 17.

Schedule UNB-7

Q. Please describe Schedule UNB-7.

A. Schedule UNB-7 shows the adjusted unbundled rates which produce the adjusted revenues as shown in lines 10 and 17 of Schedule UNB-6. The billing determinants and the base rates for transmission and distribution are the same as those shown in Schedule UNB-5. The EFC and PIPP riders were removed and several new riders were added. The base rates for generation were adjusted to reflect the elimination of the EFC rider, the relocation of DSM costs to the Universal Service Fund and Energy Efficiency Fund riders, and the residential discount. These adjusted unbundled rates were provided to Company Witness Thomas for inclusion in Schedules UNB-1 and UNB-2.

Schedule UNB-8

Q. Please describe Schedule UNB-8.

A. Schedule UNB-8 is a typical bill comparison. Customers' bills were calculated based upon typical consumption levels for each of the Companies' rate schedules.

The current bill calculations were based upon current bundled rates as shown in Schedule UNB-3 or equivalently, the unbundled rates as shown in Schedule UNB-5. The adjusted total bill calculations were based upon the adjusted unbundled rates as shown in Schedule UNB-7.

Q. Does this conclude your testimony?

A. Yes.

Companies Ex. No. 2

COLUMBUS SOUTHERN POWER COMPANY
CASE NO. 99-____-EL-ETP
PART A
UNBUNDLING PLAN

Schedule UNB-1 consists of two parts:

1. Standard Tariff – consists of the terms and conditions of service, unbundled rate schedules, and riders applicable to customers who do not choose an alternative Electric Supplier.

2. Open Access Distribution Tariff – consists of (a) the terms and conditions of service, distribution rate schedules, and riders applicable to customers who choose an alternative Electric Supplier, and (b) terms and conditions applicable to suppliers of competitive services.

Schedule UNB-1 is a complete copy of the proposed tariffs. It is not marked for changes relative to the current tariff as such changes are contained in Schedule UNB-2.

P.U.C.O. NO. 5

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(This page shall remain in effect until no later than December 31, 2005)

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RS-TOD	Residential Time-of-Day	14-1 thru 14-2	January 1, 2001
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IRP-OS	Interruptible Power – Opportunity Sales	25-5 thru 25-13	January 1, 2001
IRP-CDB	Interruptible Power – Capacity Deficiency B	25-14 thru 25-22	January 1, 2001
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COLUMBUS SOUTHER POWER
DISTRIBUTION COMPANY

Original Sheet No. 2-1

P.U.C.O. NO. 17

LIST OF COMMUNITIES SERVED

(This page shall remain in effect until no later than December 31, 2005)

COMMUNITY	COMMUNITY	COMMUNITY
Aberdeen	Creola	Johnstown
Addison	Danville	Kanauga
Albany	Darbydale	Kerr
Alexandra	Decatur	Kilbourne
Allensburg	Delaware	Kyger
Allensville	Doanville	Latham
Amesville	Dodsonville	Lawshe
Antiquity	Dublin	Leonardsburg
Athens	Dundas	Letart Falls
Bainbridge	East Monroe	Lewis Center
Belfast	Eureka	Locust Grove
Bentonville	Ewington	Londonderry
Bexley	Fincastle	Lyndon
Bidwell	Firebrick	Lynx
Bishopville	Floodwood	Lyra
Blackfork	Frost	Macon
Blue Creek	Gahanna	Manchester
Boston	Galena	Marble Cliff
Bourneville	Gallipolis	Marshall
Bradbury	Galloway	Massieville
Brice	Grandview Heights	McArthur
Buchtel	Grove City	McDermott
Buford	Groveport	McLeish
Carbondale	Guysville	Middleport
Carbon Hill	Hamden	Millfield
Carpenter	Harrisburg	Mineral
Centerburg	Harrisonville	Minersville
Centerville (Thurman P.O.)	Hartford (Croton P.O.)	Minerva Park
Chauncey	Haydenville	Mowrystown
Cherry Fork	Hemlock Grove	Murray City
Cheshire	Hilliard	Mt. Pleasant
Chester	Hillsboro	Mt. Sterling
Chillicothe	Hockingport	Nelsonville
Circleville	Hollister	New Albany
Coalton	Idaho	New Marshfield
Columbus	Jackson (Part)	New Martinsburg
Coolville	Jacksonville	New Petersburg

(Continued on Sheet No. 2-2)

Filed pursuant to Order No. 99-xxxx-EL-ETP dated

Issued:

Effective: January 1, 2001

Issued by
Marsha P. Ryan, Vice President
Columbus, Ohio

COLUMBUS SOUTHER POWER
DISTRIBUTION COMPANY

Original Sheet No. 2-2

P.U.C.O. NO. 17

LIST OF COMMUNITIES SERVED

(This page shall remain in effect until no later than December 31, 2005)

COMMUNITY	COMMUNITY	COMMUNITY
New Plymouth	Sugar Tree Ridge	
New Rome	Summit Station	
Northrup	Sunbury	
Oak Hill	The Plains	
Obetz	Torch	
Orient	Trimble	
Otway	Tuppers Plains	
Pataskala	Union Furnace	
Pedro	Upper Arlington	
Peebles	Urbancrest	
Piketon	Valleyview	
Pomeroy	Vigo	
Porter	Vinton	
Portland	Waverly	
Powell	Wellston	
Radcliff	Westerville (Part)	
Rarden	West Jefferson (Jefferson)	
Rainsboro	West Untion	
Ray	Whitehall	
Reedsville	Wilkesville	
Reynoldsburg	Winchester	
Richmondale	Worthington	
Rio Grande	Zaleski	
Riverlea		
Roads		
Rock Springs		
Rodney		
Rome (Stout P.O.)		
Sardinia		
Scioto Furnace		
Seaman		
Shade		
Sharpsburg		
Sinking Spring		
South Salem		
South Webster		
Stewart		

Filed pursuant to Order No. 99-xxxx-EL-ETP dated

Issued:

Effective: January 1, 2001

Issued by
Marsha P. Ryan, Vice President
Columbus, Ohio

TERMS AND CONDITIONS OF SERVICE

(These Terms and Conditions of Service shall remain in effect until no later than December 31, 2005)

1. CONTRACTS, APPLICATIONS OR REQUESTS FOR SERVICE

These Terms and Conditions of Service apply to service under the Company's schedules which provide for generation, transmission and distribution service. Customers requesting only distribution service from the Company, irrespective of the voltage level at which service is taken, as provided for in Section 4928.40(E), Ohio Revised Code, shall be served under the Company's open access distribution schedules and the Terms and Conditions of Open Access Distribution Service shall apply.

Electric service shall be made available to a prospective customer within this Company's area of service upon request or execution of a contract therefore and its acceptance by an officer or authorized representative of the Company. The request may be either over the phone or in person.

The character of service and the rates, rules, terms, regulations and conditions shall be in accordance with P.U.C.O. No. 5, the supplements thereto and revisions thereof applying to the particular type of service and locality for which such contract or application is made.

2. TERM OF CONTRACT

Except as limited by law and as provided in rate schedules, requests or contracts for service shall be for the term requested or as provided in the individual contract of the customer.

3. CONDITIONS OF SERVICE

Before the Company shall be required to furnish service, the Company may require that the customer submit specifications of electrical apparatus to be operated by service to be furnished by the Company, giving the location of his buildings. The Company will specify the character of the current it will furnish, and the point at which service will be brought in.

Each separate point of delivery shall be considered a Contract Location and shall be metered and billed under a separate request or contract for service.

If the Company requires separate points of delivery, for like service, to meet the customer's electrical requirements at a single Contract Location, the metering for two or more points of delivery may be combined for billing under the applicable tariff.

(Continued on Sheet No. 3-2)

TERMS AND CONDITIONS OF SERVICE

(These Terms and Conditions of Service shall remain in effect until no later than December 31, 2005)

4. AVAILABLE RATES

A copy of these Terms and Conditions of Service and the schedules applicable to the customer's class of business will be furnished upon request.

If the customer can meet the requirements of more than one rate schedule, the Company will endeavor to advise the customer as to which rate schedule is the most advantageous for the prospective service. The customer shall then select the rate schedule upon which the contract for service shall be based. The Company under no circumstances guarantees that the rate under which a customer is billed is the most favorable rate.

The customer may change the initial rate schedule selection to another applicable rate schedule at any time by either written notice to Company and/or by executing a new contract for the rate schedule selected, provided that the application of such subsequent selection shall continue for 12 months before any other selection may be made, except when an existing rate is modified or a new rate schedule is offered.

5. SERVICE CONNECTIONS

In areas served by an overhead distribution system, an overhead service shall be provided by the Company from the Company's distribution system extending one span (approximately 100 feet) toward the customer's facilities. Where greater length is required by the customer, the cost of additional facilities shall be borne by the customer, unless otherwise agreed upon by the customer and Company. Rights of way or easements necessary for the installation of said service (including private railway wire crossings) shall be provided by the customer.

It is recommended that service wires not smaller in size than #6 shall be brought out of the building in an approved manner from the main service disconnect to the outside of the building. The point of outlet shall be as high as the construction of the building will permit, but not more than 25 feet nor less than 10 feet from the ground (for exception-see National Electric Code) and shall be located at a point convenient to the Company's lines for making connections thereto, and each of the service wires shall extend at least 3 feet from weatherhead on end of conduit or cable for making service connections. Service entrance equipment shall be properly grounded and shall be installed so that the disconnecting means is readily accessible.

Conduit and wires and any equipment, installation and appurtenances furnished, installed and maintained by the customer must conform to the National Electrical Code, as well as applicable governmental requirements.

(Continued on Sheet No. 3-3)

TERMS AND CONDITIONS OF SERVICE

(These Terms and Conditions of Service shall remain in effect until no later than December 31, 2005)

A customer desiring an underground service from overhead wires shall, at the customer's expense, install and maintain service wires in an approved manner from main entrance switch in building to available pole (designated by the Company) from which connection is to be made, including the necessary run of conduit and wires up the pole. Such underground service shall conform to Company specifications.

The Company shall not be required to make any inspection of the wiring, safety switch or other equipment, installation or appurtenances installed and owned by the customer. Any inspection thereof which the Company may make shall be voluntary on its part and for its benefit only, and shall not in any way relieve the customer of any obligations in that respect.

6. METERS AND METERING EQUIPMENT

The Company will own, furnish, install and maintain the meter or meters. The Company will own, furnish and maintain the meter enclosures or sockets. The customer is required to install and maintain the mounting or meter enclosures or sockets. The Company may specify whether the meter or meters are to be installed on the inside or outside the customer's premise and may change such location at its option. When an inside meter installation is made, the customer shall furnish, at the customer's sole expense a suitable meter panel in a convenient and suitable location and so placed that the meter installation will not be more than 7 feet nor less than 4 feet from the floor. If the location provided by the customer causes the meter to register incorrectly, the Company may require the customer to provide a new meter location acceptable to the Company and to pay the expense of relocation. All costs incident to the relocation of an outside meter made upon the customer's request, or required to be made because of the customer's use of the customer's premises, shall be paid by the customer. The authorized agents or employees of the Company shall have free access at all reasonable hours to the premises of the customer for the purpose of installing, reading, testing and removing meters or other appliances, belonging to the Company.

The customer shall not interfere with, or allow others to interfere with, the Company's meter or any of the wiring on the line side of the meter.

7. METER TESTING

The Company will test its meters at its discretion or at the request of the customer. Any meter found by test to be registering two percent or less than two percent either fast or slow will be considered as registering accurately.

(Continued on Sheet No. 3-4)

TERMS AND CONDITIONS OF SERVICE

(These Terms and Conditions of Service shall remain in effect until no later than December 31, 2005)

The Company will test the meter at the request of the customer once at no charge to the customer. Each subsequent test, in which the meter is found to be registering accurately, will result in the cost of such test being borne by the customer.

8. DEMAND TESTING

Periodic tests for determination of demand, where provided for in various schedules, will be made at the request of the customer, provided that not more than two such requests will be made in any 12 month period.

9. DEPOSITS

The Company may require a deposit by the customer not exceeding the amount of the estimated monthly average cost of the annual consumption by such customer plus thirty percent, unless such customer be a financially responsible freeholder or give reasonably safe guaranty in an amount sufficient to secure the payment of bills for a sixty days' supply. On any such deposit the customer shall be entitled to interest at the rate of five percent per annum, provided such deposit be left with the Company at least six consecutive months.

10. CUSTOMER'S LIABILITY

In the event of loss of or injury to the property or equipment of the Company through misuse or negligence of the customer or the customer's employees or invitees, the cost of any necessary repairs or replacement shall be repaid to the Company by the customer. The customer will be held responsible for any tampering or interfering with or breaking the seals of meters or other equipment of the Company installed on the customer's premises and will be held liable for the same according to law.

No responsibility of any kind shall attach to the Company for or on account of any loss, injury or damage caused by or resulting from defects in or inadequacy of the wires, switches, equipment, or appurtenances of the customer, or from the installation, maintenance or use thereof.

11. USE AND RESALE OF ENERGY

Electric service will not be supplied to any party contracting with the Company for electric service (hereinafter in this Section 11 called "Customer") except for use exclusively by (i) the Customer at the premises specified in the service request on contract between the Company and the Customer under which service is supplied and (ii) the occupants and tenants of such premises.

(Continued on Sheet No. 3-5)

TERMS AND CONDITIONS OF SERVICE

(These Terms and Conditions of Service shall remain in effect until no later than December 31, 2005)

Resale of energy will be permitted only by legitimate electric public utilities subject to the jurisdiction of the Public Utilities Commission of Ohio and only by written consent of the Company. In addition, resale of energy will be permitted for electric service and related billing as they apply to the resale or redistribution of electrical service from a landlord to a tenant where the landlord is not operating as a public utility, and the landlord owns the property upon which such resale or redistribution takes place.

12. BILLING AND BILLS PAYABLE

The customer will be held responsible for all charges for electric energy delivered at the customer's premises. Bills will be rendered for each month's use by the Company to the customer and are payable by mail, checkless payment plan, electronic payment plan or at an authorized payment agent of the Company, on or before the due date thereon specified. Failure to receive a bill will not entitle the customer to any discount or to the remission of any charge for nonpayment within the time specified.

If the customer fails to pay in full any final bill for service rendered and said customer receives like service at another location, the Company may transfer the unpaid balance of the final bill to the service account for any such other location. Like service refers to an end use within the following broad categories: residential, commercial, or industrial. Such amount shall be designated as a past-due amount on the account at such location and subject to collection and disconnection action in accordance with Chapter 4901:1-18 of the Ohio Administrative Code and the Company's filed tariffs, terms and conditions of service, provided that such transfer of a final bill shall not be used to disconnect service to a residential consumer who is not responsible for such bill.

The word "month" as used herein and in rates schedules is hereby defined to be the time elapsed between two successive meter readings for the summer period of not less than 28 days nor more than 33 days apart and for the winter period of not less than 28 days nor more than 35 days apart. In the event of the stoppage or the failure of any meter to register the correct amount of current consumed, the customer will be billed for such period for an estimated consumption based either upon his use of energy in a similar period of like use or upon a determination based on meter test or from both of these methods combined. Except for residential service accounts, when any bill for electric service supplied by the Company is not paid within fifteen days after the due date thereon, the Company may disconnect its service, without further notice, and will not be required to reconnect service until all charges are paid. A reconnection charge commensurate with the cost of the reconnection, but not less than two dollars and fifty cents may be made for the reconnection of service. For disconnect provisions relating to residential service, see Section 23.

13. COLLECTION, RECONNECTION, AND BAD CHECK CHARGES

For charges relating to collection trips, reconnection of service, and bad checks, see Sheet No. 5-1.

(Continued on Sheet No. 3-6)

TERMS AND CONDITIONS OF SERVICE

(These Terms and Conditions of Service shall remain in effect until no later than December 31, 2005)

14. SERVICE INTERRUPTIONS

The Company will use reasonable diligence in furnishing a regular and uninterrupted supply of electric energy, but in case such supply should be interrupted or fail by reason of an act of God, public enemy, accidents, strikes, legal process, Federal or State or Municipal interference, extraordinary repairs, breakdowns, or damage to the Company's facilities, or for any other reason beyond its control, the Company shall not be liable for damages to the customer because of such interruption or failure.

The Company shall not be liable to the customer for any loss, injury or damage resulting from the customer's use of his equipment or from the use of the energy of the Company, or from the connection of the Company's wires with the customer's wires and appliances.

15. NOTICE TO COMPANY BEFORE INCREASING LOAD

The service connection, transformers, meters and appliances supplied by the Company for each customer have a definite capacity, and no significant additions to the equipment or load connected thereto shall be made until after the consent of the Company has been obtained.

16. NOTICE TO COMPANY OF ANY DEFECT IN ELECTRIC SUPPLY

The customer shall notify the Company promptly of any defect in service or any trouble or accident to the electrical supply.

17. TEMPORARY AND SPECIAL SERVICE

The customer shall pay to the Company the cost of establishing service and of removing its equipment when the service is of short term or emergency character, and a cash deposit covering the estimated net cost of such work may be required of the customer before the work is commenced.

The Company shall not be required to construct general distribution lines underground unless the cost of such special construction for general distribution lines and/or the cost of any change of existing overhead general distribution lines to underground which is required or specified by a municipality or other public authority (to the extent that such cost exceeds the cost of construction of the Company's standard facilities) shall be paid for by that municipality or public authority. The "cost of any change" as used herein, shall be the cost to the Company of such change. The "cost of special construction" as used herein, shall be the actual cost to the Company in excess of the cost of standard construction. When a charge is to be based on the excess cost, the Company and municipality or other public authority shall negotiate the amount thereof.

(Continued on Sheet No. 3-7)

TERMS AND CONDITIONS OF SERVICE

(These Terms and Conditions of Service shall remain in effect until no later than December 31, 2005)

Other service requested by a customer and considered by the Company to be either of a temporary nature, or service of a type requiring facilities the estimated net cost of which is not justified by the anticipated revenue therefrom, or special construction (costs of special construction that exceed the cost of standard construction) will be provided by the Company under special contract. Such contract shall guarantee the net cost of the additional facilities prior to the construction thereof by either a contribution in aid of construction or by deposit as set forth in any applicable supplement or supplements to the rate schedules set forth in P.U.C.O. No. 5, if any.

Service to customers using energy only during certain seasons of a year at the same location, and requiring facilities which may not be completely removed and replaced, shall not be classed as temporary service.

18. USE OF ENERGY BY CUSTOMER

The apparatus or appliances connected to the Company's lines shall be suitable in every respect to the service supplied by the Company, and shall not be operated in a manner which will cause voltage fluctuations or disturbances in the Company's distributing system or which will be detrimental to the Company's service in any way. All equipment used by the customer shall be of such type as to secure the highest practicable commercial efficiency, power factor and the proper balancing of phases, and shall be protected by proper circuit opening devices approved by the Company. Motors which are frequently started, or motors arranged for automatic control, must be of a type to give maximum starting torque with minimum current flow, and be equipped with controlling devices approved by the Company. If neon, fluorescent and other types of lighting equipment have similar power factor characteristics are installed after the effective date hereof, the customer may be required, upon notice in writing from the Company, to furnish, install, and maintain at the customer's own expense corrective apparatus to increase the power factor of the individual units or the entire group of such units to not less than 90%.

The operation of certain electrical equipment can result in disturbances (e.g., voltage fluctuations, harmonics, etc.) on the Company's transmission and distribution systems which can adversely impact the operation of equipment for other customers. Nonresidential customers are expected to abide by industry standards, such as those contain in ANSI/IEEE 519 or the IEEE/GE voltage flicker criteria, when operating such equipment. In accordance with the Electric Service and Safety Standards, Chapter 4901:1-10-15 (D) of the Ohio Administrative Code, the Company may refuse or disconnect service to nonresidential customers for using electricity or equipment which adversely affects distribution service to other customers. Copies of the applicable criteria will be provided upon request.

The Company's service shall not be operated in parallel with any source or sources of power supply except under special circumstances and upon written consent of the Company.

(Continued on Sheet No. 3-8)

TERMS AND CONDITIONS OF SERVICE

(These Terms and Conditions of Service shall remain in effect until no later than December 31, 2005)

19. LOCATION AND MAINTENANCE OF COMPANY'S EQUIPMENT

The Company shall have the right to erect and maintain its poles, lines, and circuits on the property, and to place and maintain its transformers and other apparatus on the property or within the buildings of the customer at convenient locations. The customer shall allow the use of suitable space for the installation of necessary measuring instruments so that the latter may be protected from damage.

Transformers and appurtenances placed on the property or within the building shall be housed in accordance with the National Electrical Code in a suitable room or vault provided by the customer and, when installed outside upon a mat or slab, shall be protected by an enclosure erected by the customer to guard against loss, damage or injury to persons or property.

20. COMPANY'S AGENTS NOT EMPOWERED TO CHANGE TARIFFS

No agent or employee of the Company has authority to amend, modify, alter the application, rates, terms, conditions, rules or regulations of the Company on file with the Public Utilities Commission of Ohio, or to make any promises or representations not contained in P.U.C.O. No. 5, supplements thereto and revisions thereof.

21. CHANGE OF RATES OR REGULATIONS

Rules and Regulations and rates contained herein are subject to cancellation or modification upon order or permission of the Public Utilities Commission of Ohio.

22. DISCONNECT PROVISIONS - NON-RESIDENTIAL
Reasons for Disconnect

The Company reserves the right to discontinue the supply of electric energy and disconnect its lines and remove its property for any of the following reasons:

(A) For any violation of or refusal to comply with the contract and/or the general service rules and regulations on file with the Commission which apply to the customer's service;

(B) In the event the customer uses electricity in a manner detrimental to the service to other customers;

(C) When providing service is in conflict or incompatible with any order of the Commission, laws of the State of Ohio or any political subdivision thereof, or of the federal government or any of its agencies;

(D) When the customer has moved from the premises;

(Continued on Sheet No. 3-9)

TERMS AND CONDITIONS OF SERVICE

(These Terms and Conditions of Service shall remain in effect until no later than December 31, 2005)

(E) When supplying electricity to any customer creates a dangerous condition on the customer's premises or where, because of conditions beyond the customer's premises, termination of the supply of electricity is reasonably necessary. Service will not be restored until such dangerous condition or conditions have been corrected;

(F) In the event the customer resorts to any fraudulent practice in the obtaining of electricity supplied, or is the beneficiary of any such fraudulent practice, or the Company's meter, metering equipment, or other property used to supply the service has been damaged by the customer, the customer's employees or agents.

Service will not be restored until the customer has given satisfactory assurance that such fraudulent or damaging practice will be discontinued and has paid to the Company an amount estimated by the Company to be reasonable compensation for service fraudulently obtained and not paid for and for any damage to property of the Company including any cost to repair the damage;

(G) For repairs, provided that notice to customers will be given prior to scheduled maintenance interruptions in excess of six hours;

(H) For non-payment; and

(I) Upon the request of the customer.

Suspension of service for any of the above reasons shall not terminate the contract for service. The authorized agents or employees of the Company shall have free access at all reasonable hours to the premises of the customer for purposes of disconnecting and reconnecting service.

23. ESTABLISHMENT OF CREDIT FOR RESIDENTIAL UTILITY SERVICE AND DISCONNECT, RECONNECT - PROCEDURES - RESIDENTIAL

The Company's rules for the establishment of credit for residential utility service is governed by Chapter 4901:1-17 of the Ohio Administrative Code, and the Company's disconnect and reconnect procedures for residential customers is governed by Chapter 4901:1-18 of the Ohio Administrative Code. A copy of the above chapters are available for public inspection upon request.

24. DEFINITION OF RESIDENTIAL CUSTOMER

The Residential Customer is a customer whose domestic needs for electrical service are limited to their primary single family residence, single occupancy apartment and/or condominium, mobile housing unit, or any other single family residential unit.

(Continued on Sheet No. 3-10)

THE FOLLOWING IMAGES WERE SCANNED AS RECEIVED.

TERMS AND CONDITIONS OF SERVICE

(These Terms and Conditions of Service shall remain in effect until no later than December 31, 2005)

The residential rate schedules do not apply to commercial or industrial service. If a residential unit is used for both residential and commercial purposes, the appropriate general service rate shall apply unless the wiring is so arranged that the residential usage can be separately metered. The hallways and other common facilities of an apartment and condominium building or apartment and condominium complex are to billed on the appropriate general service rate.

In the event a detached garage or other facility on a Residential Customer's property is separately served and metered, such facility shall accordingly be metered and billed according to the appropriate general service rate.

25. NOMINAL SERVICE VOLTAGES

The Company has established the following nominal service voltages of which at least one of the following characteristics shall be made available to a customer, the particular voltage and service characteristics to be at the option of the Company:

Secondary Distribution System - /alternating current, 60 cycles at nominal voltages of 120, 120/208, 120/240 or 240/480 volts, single phase; and 120/208, 120/240, 240, 240/480, 227/480, 480, 2400 and 2400/4160 volts, 3 phase.

Primary Distribution System - Alternating current, 60 cycles at nominal voltages of 12,470, 13,200, 13,800 and 34,500 volts, 3 phase.

Subtransmission - Alternating current, 60 cycles, 3 phase at nominal, unregulated voltage of 40,000 volts or 69,000 volts.

Transmission - Alternating current, 60 cycles, 3 phase at nominal, unregulated voltage of 138,000 volts.

RURAL LINE EXTENSION PLAN
DEFINITIONS, RULES AND REGULATIONS

(This page shall remain in effect until no later than December 31, 2005)

AVAILABILITY OF SERVICE

This plan is applicable for permanent light, power and domestic service to rural customers. Electric energy will be made available to such customers adjacent to distribution lines carrying less than 15,000 volts upon guarantee of revenue as herein provided. Electric Company may in particular cases, be relieved by the Commission from the duty of tapping lines.

DEFINITIONS

"Electric Company" shall be taken to mean Columbus Southern Power Company.

"Customer" shall be taken to mean any applicant for electric service from a line extension, exclusive of industrial or manufacturing plants, who shall have contracted with the Electric Company to take and pay for the same for a definite period of time, under schedules filed by such Electric Company and approved by the Commission.

"Line Extension" shall be taken to mean the provision of such facilities (poles, fixtures, wires and appurtenances) as are necessary for delivering electrical energy for general use along public highways or Electric Company's right-of-way to one or more customers so located that they cannot be adequately supplied from a secondary system of the Electric Company's existing distribution system.

"Point of Origin" shall be taken to mean the point where a line extension made under this plan connects with and receives energy from any existing transmission or distribution line. Said point shall be the nearest practical point to the Customers to be served by said extension.

"Construction Cost" shall be taken to mean the cost of constructing any line extension, and shall include all costs of labor and materials directly chargeable to and necessary to construct the line extension, and all transformers, meters, services, rights-of-way, tree trimming rights, highway permits, actually paid for by said Company and all other elements of actual cost properly chargeable to or against the line extension. Electric Company may, for the purpose of standardization, establish standard construction cost estimates which shall not exceed, in any event, the average cost of constructing such line in the territory involved, in which case the term "Construction Cost" as used in this plan will be understood to mean the standard estimate thus established. Items of Cost shall be classified according to the "Uniform Classification of Accounts for Electric Companies" prescribed by the Public Utilities Commission of Ohio.

"Service" means wires and other appurtenances of adequate capacity from the nearest or most suitable pole of the line extension of the Electric Company, extending not to exceed one service span or approximately 100 feet in length toward the pole, building or terminal connection provided by the Customer.

"Commission" means the Public Utilities Commission for the State of Ohio.

(Continued on Sheet No. 4-2)

RURAL LINE EXTENSION PLAN
DEFINITIONS, RULES AND REGULATIONS

(This page shall remain in effect until no later than December 31, 2005)

LINE EXTENSIONS

The Electric Company will make line extensions within its territory provided applicants on such extensions shall, after the establishment of permanency and credit, contract for payment for energy supplied them in accordance with the Electric Company's applicable schedule filed supply of such energy, and thus become Customers, as defined.

Such extensions will be installed and put into operation within six months after date of said contracts and the establishment of permanency and credit and when satisfactory rights-of-way have been established, provided the Company will not be required to start construction until ninety percent of the applicants have entered into for contracts wiring of their premises and fifty percent of such applicants have completed the wiring of their premises and are ready for service.

RATES

The rates applicable to such customers shall be the rates set forth in schedules on file with the Public Utilities Commission of Ohio for service under this plan.

CONSTRUCTION PLAN

The Electric Company will construct in accordance with its "Standard of Construction" and thereafter operate and maintain at its own cost line extensions required to serve any customers, who will guarantee revenues therefrom in sufficient amount to comply with the schedules of the Company as filed with the Public Utilities Commission of Ohio and with the conditions as set forth under "Guarantee of Revenue."

In determining the revenues originally so to be guaranteed and any subsequent changes therein:

(A) The total construction cost of the line extension shall be credited with all money, labor, materials or other items of cost contributed by said Customers, at the cost to the Electric Company of all items entering into said contributions and total revenue to be guaranteed shall be based upon cost after credit as aforesaid.

(B) Appropriate adjustments shall be made annually as of July first of each year, in the amount of revenue guaranteed by each Customer, on account of change in the number and/or classification of customers supplied from the line extension.

(Continued on Sheet No. 4- 3)

RURAL LINE EXTENSION PLAN
DEFINITIONS, RULES AND REGULATIONS

(This page shall remain in effect until no later than December 31, 2005)

GUARANTEE OF REVENUE

Except where otherwise provided for in the applicable schedule, Customers served by said line extension shall guarantee during the initial contract period of four years, for service supplied under applicable schedule of rates, a monthly payment to the Electric Company equal to two percent of the total Construction Cost" of the line extension as defined herein, and thereafter a minimum monthly charge of not to exceed two percent of such "Construction Cost" provided, however, that in no case shall said guarantee or said minimum monthly charge be less than the minimum monthly charge specified in the filed schedule applicable to said Customers service. For Customers served prior to May 21, 1992, except where otherwise provided for in the applicable schedule, Customers served by said line extension shall guarantee during the initial contract period of four years, for service supplied under the applicable schedule of rates, a monthly payment to the Electric Company equal to one percent of the total "Construction Cost" of the line extension as defined herein, and thereafter a minimum monthly charge not to exceed one percent of such "Construction Cost" provided, however, that said guarantee or said minimum monthly charge be less than the minimum monthly charged specified in the filed schedule applicable to said Customer's service.

ESTABLISHMENT OF PERMANENCY AND CREDIT

Permanency as used herein is defined as a residence that is permanently affixed and has an environmentally approved water and sewage system provided or planned.

If electric service is requested prior to the installation of an approved water and sewage system, the Company may require from the governing authority evidence of the system's approval. The Company also may require a letter of intent from the Customer regarding the system's installation. If the approved water and sewage system has not been installed within ninety (90) days after the establishment of electric service, the Company may declare the residence temporary and require payment of full construction and removal cost of Company facilities.

The Electric Company in order to safeguard its investments, may require any applicant Customer to establish a satisfactory credit standing as a guarantee of the payment of his bills during the term of the contract, or, in lieu thereof, to make a suitable cash deposit.

(Continued on Sheet No. 4-4)

RURAL LINE EXTENSION PLAN
DEFINITIONS, RULES AND REGULATIONS

(This page shall remain in effect until no later than December 31, 2005)

APPORTIONMENT AND ADJUSTMENT OF GUARANTEES

Said monthly guarantees shall be apportioned among those to be served in the ratio which the minimum monthly payment specified in the applicable schedule bears to the total of all such minimum in the contract for service from the given line extension, provided that for the purpose of calculation, as herein provided, the minimum monthly payment for residential lighting shall in all cases be considered to be not less than one dollar. Nothing herein contained shall, however, preclude any Customer from assuming more than his pro-rata share of such guarantee subject to acceptance thereof by the Electric Company. Customers added to an extension already established shall guarantee revenue to the Electric Company to the same extent and in the same manner as is then currently guaranteed by other Customers of the same class served from the line extension. The minimum monthly guarantee shall be reapportioned annually in the manner described above, among all Customers supplied from the line extension.

EXTENSION TO ADDITIONAL CUSTOMERS

Additional Customers shall be connected to a line extension already built or to a further extension thereof upon the same terms and conditions as would apply were the extension them being made for all Customers including the new Customers, provided the inclusion of such new Customers will not increase the cost to the existing customers on such extension. Otherwise, any line extension constructed to service additional Customers shall be considered and treated as a new and separate line extension.

CUSTOMER'S WIRING AND EQUIPMENT

All wiring and equipment on the premises of the Customer, for utilization of service, shall be installed and maintained at the expense of the Customer in a manner to conform with the rules and requirement of any recognized inspection service in effect in the community, and to a standard satisfactory to the Electric Company.

The Customer shall also furnish, install, and maintain any poles, wires and other construction necessary to bring the terminus of his wiring to a location where it can be connected to the Electric Company's line extension by a service span, as herein defined, to be supplied by the Electric Company, and the Electric Company shall have the right at any time to discontinue service being supplied to such equipment if it is deemed such equipment is not in accordance with accepted practices. Such disconnection shall not be considered a cancellation of the agreement, and shall not relieve the Customer from the payment of proper minimum charges during the full period that service is disconnected.

(Continued on Sheet No. 4-5)

RURAL LINE EXTENSION PLAN
DEFINITIONS, RULES AND REGULATIONS

(This page shall remain in effect until no later than December 31, 2005)

TITLE TO LINE EXTENSIONS FINANCED IN PART BY CUSTOMERS

The Electric Company shall not be obligated to deliver energy to any line extension financed in part by Customers until every Customer participating in said financing shall have agreed in writing that the ownership of such line extension shall be vested in the Electric Company and thereafter said Company shall be obligated to maintain such lines.

TERM OF CONTRACT

The initial term of contract shall be four (4) years, and thereafter shall be governed by the provision of the applicable schedule.

MISCELLANEOUS DISTRIBUTION CHARGES

(This page shall remain in effect until no later than December 31, 2005)

COLLECTION CHARGE

When any bill for electric service by the Company is not paid within fifteen days after the due date thereon, a collection charge of $8.00 will be assessed if a collection trip to the Customer's premises is made.

During the period from November 1 through April 15, the Company makes a second trip if collection is not made on the first trip, even though contact on the first trip took place. The second trip will be made at least 10 days later only if the account remains delinquent. During the remainder of the year, only one trip will be made to the Customer's premises.

The collection charge of $8.00 will be assessed to the account every time a collection trip is made. The Company, normally, would make no more than two trips per month to any one Customer's premises.

BAD CHECK CHARGE

When a check received from a Customer in payment for service rendered is not honored by the bank the Customer will be charged $6.00 to pay the additional cost incurred by the Company for processing the check, unless the Customer shows that the bank was in error.

RECONNECTION CHARGE

When service has been terminated for nonpayment, the following charges shall apply for reconnection of service.

During Normal Business Hours	
Reconnect at Meter	$11.30
Reconnect at Pole	60.00
Remove and Reset Meter	28.00
Install Locking Device and Reconnect	38.00

Other Than Normal Business Hours	Off-Shift	Sunday
Reconnect at Meter	$ 80.00	$105.00
Reconnect at Pole	180.00	230.00

Normal hours for reconnection are 7:30 A.M. to 4:00 P.M. all weekdays excluding holidays.

When service has been terminated, at the Customer's request, for non-credit related reasons, the Customer will be assessed a $30.00 charge for the disconnection, as well as a $30.00 charge for the subsequent reconnection.

(Continued on Sheet No. 5-2)

MISCELLANEOUS DISTRIBUTION CHARGES

(This page shall remain in effect until no later than December 31, 2005)

METER TEST CHARGE

The Company will test the meter at the request of the Customer. The first test shall be at no charge to the Customer. The Company shall charge $28.00 for any subsequent tests performed at the Customer's request and the meter is found to be registering accurately.

TAMPERING/INVESTIGATION CHARGE

When service has been obtained through fraudulent or damaging practices, the Customer will be charged a minimum fee of $25.00 for the Company to investigate and inspect the premises. The Customer will pay addition charges for any and all costs of disconnection as well as the costs of repairing or replacing damaged equipment based on the Customer's individual situation.

COLUMBUS SOUTHERN POWER
DISTRIBUTION COMPANY

Original Sheet No. 10-1

P.U.C.O. NO. 5

SCHEDULE R-R
(Residential Service)

Availability of Service

Available for residential electric service through one meter to individual residential customers, including those on lines subject to the Rural Line Extension Plan. This schedule shall remain in effect until no later than December 31, 2005.

Monthly Rate

	Generation	Transmission	Distribution	Total
Customer Charge ($)	--	--	4.75	4.75
Energy Charge (¢ per KWH):				
Winter:				
For the first 800 KWH used per month	4.87143	0.47593	2.54439	7.89175
For all KWH over 800 KWH used per month	1.28471	0.47593	1.95956	3.72020
Summer:				
For the first 800 KWH used per month	4.87143	0.47593	2.54439	7.89175
For all KWH over 800 KWH used per month	4.87143	0.47593	2.54439	7.89175

Seasonal Periods

The winter period shall be the billing months of October through May and the summer period shall be the billing months of June through September.

Minimum Charge

(a) The minimum monthly charge for service on lines not subject to the Rural Line Extension Plan shall be the Customer Charge.

(b) The minimum monthly charge for electric service supplied from lines subject to the Rural Line Extension Plan shall, for the initial contract period of four years, be the amount provided in the "Definitions, Rules and Regulations for Rural Line Extension Plan," but in no event shall be less than the Customer Charge.

Storage Water Heating Provision

Availability of this provision is limited to those customers served under this provision as of December 31, 2000.

If the customer installs a Company approved storage water heating system which consumes electrical energy only during off-peak hours as specified by the Company and stores hot water for use during on-peak hours, the following shall apply:

(a) For minimum capacity of 80 gallons, the last 300 KWH of use in any month shall be billed at the Storage Water Heating Energy Charge.

(Continued on Sheet No. 10-2)

Filed pursuant to Order No. 99-xxxx-EL-ETP dated

Issued:

Effective: January 1, 2001

Issued by
Marsha P. Ryan, Vice President
Columbus, Ohio

SCHEDULE R-R
(Residential Service)

Storage Water Heating Provision (Cont'd)

(b) For minimum capacity of 100 gallons, the last 400 KWH of use in any month shall be billed at the Storage Water Heating Energy Charge.

(c) For minimum capacity of 120 gallons or greater, the last 500 KWH of use in any month shall be billed at the Storage Water Heating Energy Charge.

	Generation	Transmission	Distribution	Total
Storage Water Heating Energy Charge (¢ per KWH)	2.29537	–	–	2.29537

These provisions, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For purpose of this provision, the on-peak billing period is defined as 7:00 AM to 9:00 PM local time for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays, all hours of the day on Saturdays and Sundays, and the legal holidays of New Year's Day, Presidents Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

The Company reserves the right to inspect at all reasonable times the storage water heating system and devices which qualify the residence for service under the storage water heater provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in its sole judgment the availability conditions of this schedule are being violated, it may discontinue billing the customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Customer Charge as stated in the above monthly rate.

Load Management Water Heating Provision

Availability of this provision is limited to those customers served under this provision as of December 31, 2000.

For residential customers who install a Company-approved load management water heating system which consumes electrical energy primarily during off-peak hours specified by the Company and stores hot water for use during on-peak hours, of minimum capacity of 80 gallons, the last 250 KWH of use in any month shall be billed at the Load Management Water Heating Energy Charge.

	Generation	Transmission	Distribution	Total
Load Management Water Heating Energy Charge (¢ per KWH)	2.29537	–	–	2.29537

(Continued on Sheet No. 10-3)

SCHEDULE R-R
(Residential Service)

Load Management Water Heating Provision (Cont'd)

This provision, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For purpose of this provision, the on-peak billing period is defined as 7:00 AM to 9:00 PM local time for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays, all hours of the day on Saturdays and Sundays, and the legal holidays of New Year's Day, Presidents Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

The Company reserves the right to inspect at all reasonable times the load management storage water heating system and devices which qualify the residence for service under the Load Management Water Heating Provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in its sole judgment the availability conditions of this provision are being violated, it may discontinue billing the customer under this provision and commence billing under the standard monthly rate.

Payment

Bills are due and payable in full by mail, checkless payment plan, electronic payment plan or at an authorized payment agent of the Company within 15 days after the mailing of the bill.

Applicable Riders

Monthly Charges computed under this schedule shall be adjusted in accordance with the following applicable riders:

Rider	Sheet No.
Universal Service Fund Rider	60-1
Energy Efficiency Fund Rider	61-1
KWH Tax Rider	62-1
Gross Receipts Tax Credit Rider	63-1
Property Tax Credit Rider	64-1
Municipal Income Tax Rider	65-1
Franchise Tax Rider	66-1
Regulatory Asset Charge Rider	67-1

Term of Contract

A written agreement may, at the Company's option, be required.

(Continued on Sheet No. 10-4)

SCHEDULE R-R
(Residential Service)

Special Terms and Conditions

This schedule is subject to the Company's Terms and Conditions of Service.

This schedule is intended for single phase service. Where the residential customer requests three-phase service, this schedule will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service.

Customers with cogeneration and/or small power production facilities shall take service under Schedule COGEN/SPP or by special agreement with the Company.

SCHEDULE R-R-1
(Residential Small Use Load Management Service)

Availability of Service

Available for residential electric service through one meter to individual residential customers who normally do not use more than 600 KWH per month during the summer period, including those on lines subject to the Rural Line Extension Plan. Any new customer or an existing customer who changes service location will be billed under Schedule R-R until the first billing month during the summer period. This schedule shall remain in effect until no later than December 31, 2005.

Monthly Rate

	Generation	Transmission	Distribution	Total
Customer Charge ($)	--	--	4.75	4.75
Energy Charge (¢ per KWH):				
Winter:				
For the first 700 KWH used per month	3.99667	0.47593	2.54439	7.01699
For the next 100 KWH used per month	3.99667	0.47593	2.54439	7.01699
For all KWH used over 800 KWH used per month	1.28471	0.47593	1.95956	3.72020
Summer				
For the first 700 KWH used per month	3.99667	0.47593	2.54439	7.01699

In any summer billing month if usage exceeds 700 KWH, billing will be rendered that month under Schedule R-R and thereafter for all subsequent months through the four months of the next summer period.

Seasonal Periods

The winter period shall be the billing months of October through May and the summer period shall be the billing months of June through September.

Minimum Charge

(a) The minimum monthly charge for service on lines not subject to the Rural Line Extension Plan shall be the Customer Charge.

(b) The minimum monthly charge for electric service supplied from lines subject to the Rural Line Extension Plan shall, for the initial contract period of four years, be the amount provided in the "Definitions, Rules and Regulations for Rural Line Extension Plan," but in no event shall be less than the Customer Charge.

Storage Water Heating Provision

Availability of this provision is limited to those customers served under this provision as of December 31, 2000.

(Continued on Sheet No. 11-2)

SCHEDULE R-R-1
(Residential Small Use Load Management Service)

Storage Water Heating Provision (Cont'd)

If the customer installs a Company approved storage water heating system which consumes electrical energy only during off-peak hours as specified by the Company and stores hot water for use during on-peak hours, the following shall apply:

(a) For minimum capacity of 80 gallons, the last 300 KWH of use in any month shall be billed at the Storage Water Heating Energy Charge.
(b) For minimum capacity of 100 gallons, the last 400 KWH of use in any month shall be billed at the Storage Water Heating Energy Charge.

(c) For minimum capacity of 120 gallons or greater, the last 500 KWH of use in any month shall be billed at the Storage Water Heating Energy Charge.

	Generation	Transmission	Distribution	Total
Storage Water Heating Energy Charge (¢ per KWH)	2.29537	--	--	2.29537

These provisions, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above. In addition, the KWH billed under this provision shall not apply to the 700 KWH eligibility requirement for service under this schedule.

For purpose of this provision, the on-peak billing period is defined as 7:00 AM to 9:00 PM local time for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays, all hours of the day on Saturdays and Sundays, and the legal holidays of New Year's Day, Presidents Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

The Company reserves the right to inspect at all reasonable times the storage water heating system and devices which qualify the residence for service under the storage water heater provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in its sole judgment the availability conditions of this schedule are being violated, it may discontinue billing the customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Customer Charge as stated in the above monthly rate.

Load Management Water Heating Provision

Availability of this provision is limited to those customers served under this provision as of December 31, 2000.

(Continued on Sheet No. 11-3)

SCHEDULE R-R-1
(Residential Small Use Load Management Service)

Load Management Water Heating Provision (Cont'd)

For residential customers who install a Company-approved load management water heating system which consumes electrical energy primarily during off-peak hours specified by the Company and stores hot water for use during on-peak hours, of minimum capacity of 80 gallons, the last 250 KWH of use in any month shall be billed at the Load Management Water Heating Energy Charge.

	Generation	Transmission	Distribution	Total
Load Management Water Heating Energy Charge (¢ per KWH)	2.29537	--	--	2.29537

This provision, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above. In addition, the KWH billed under this provision shall not apply to the 700 KWH eligibility requirement for service under this schedule.

For purpose of this provision, the on-peak billing period is defined as 7:00 AM to 9:00 PM local time for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays, all hours of the day on Saturdays and Sundays, and the legal holidays of New Year's Day, Presidents Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

The Company reserves the right to inspect at all reasonable times the load management storage water heating system and devices which qualify the residence for service under the Load Management Water Heating Provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in its sole judgment the availability conditions of this provision are being violated, it may discontinue billing the customer under this provision and commence billing under the standard monthly rate.

Payment

Bills are due and payable in full by mail, checkless payment plan, electronic payment plan or at an authorized payment agent of the Company within 15 days after the mailing of the bill.

Applicable Riders

Monthly Charges computed under this schedule shall be adjusted in accordance with the following applicable riders:

(Continued on Sheet No. 11-4)

SCHEDULE R-R-1
(Residential Small Use Load Management Service)

Applicable Riders (Cont'd)

Rider	Sheet No.
Universal Service Fund Rider	60-1
Energy Efficiency Fund Rider	61-1
KWH Tax Rider	62-1
Gross Receipts Tax Credit Rider	63-1
Property Tax Credit Rider	64-1
Municipal Income Tax Rider	65-1
Franchise Tax Rider	66-1
Regulatory Asset Charge Rider	67-1

Term of Contract

A written agreement may, at the Company's option, be required.

Special Terms and Conditions

This schedule is subject to the Company's Terms and Conditions of Service.

This schedule is intended for single phase service. Where the residential customer requests three-phase service, this schedule will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service.

Customers with cogeneration and/or small power production facilities shall take service under Schedule COGEN/SPP or by special agreement with the Company.

COLUMBUS SOUTHERN POWER
DISTRIBUTION COMPANY

Original Sheet No. 12-1

P.U.C.O. NO. 5

SCHEDULE RLM
(Residential Optional Demand Service)

Availability of Service

Available for optional residential electric service through one meter to individual residential customers including those on lines subject to the Rural Line Extension Plan. This schedule provides an incentive for customers to minimize peak demand usage imposed on the Company and requires the installation of demand metering facilities. This schedule shall remain in effect until no later than December 31, 2005.

Monthly Rate

	Generation	Transmission	Distribution	Total
Customer Charge ($)	--	--	7.50	7.50
Energy Charge (¢ per KWH):				
Winter:				
For the first 750 KWH used per month	4.56725	0.63593	3.23658	8.43976
For the next 150 KWH per KW in excess of 5 KW Billing Demand used per month	2.35443	0.21550	1.09678	3.66671
For all addition KWH used per month	2.79679	--	--	2.79679
Summer:				
For the first 750 KWH used per month	4.56725	0.63593	3.23658	8.43976
For the next 150 KWH per KW in excess of 5 KW Billing Demand used per month	4.32584	0.59006	3.00313	7.91903
For all addition KWH used per month	4.03117	--	--	4.03117

Seasonal Periods

The winter period shall be the billing months of October through May and the summer period shall be the billing months of June through September.

Minimum Charge

(a) The minimum monthly charge for service on lines not subject to the Rural Line Extension Plan shall be the Customer Charge.

(b) The minimum monthly charge for electric service supplied from lines subject to the Rural Line Extension Plan shall, for the initial contract period of four years, be the amount provided in the "Definitions, Rules and Regulations for Rural Line Extension Plan," but in no event shall be less than the Customer Charge.

Storage Water Heating Provision

Availability of this provision is limited to those customers served under this provision as of December 31, 2000.

(Continued on Sheet No. 12-2)

Filed pursuant to Order No. 99-xxxx-EL-ETP dated

Issued:

Effective: January 1, 2001

Issued by
Marsha P. Ryan, Vice President
Columbus, Ohio

SCHEDULE RLM
(Residential Optional Demand Service)

Storage Water Heating Provision (Cont'd)

If the customer installs a Company approved storage water heating system which consumes electrical energy only during off-peak hours as specified by the Company and stores hot water for use during on-peak hours, the following shall apply:

(a) For minimum capacity of 80 gallons, the last 300 KWH of use in any month shall be billed at the Storage Water Heating Energy Charge.

(b) For minimum capacity of 100 gallons, the last 400 KWH of use in any month shall be billed at the Storage Water Heating Energy Charge.

(b) For minimum capacity of 120 gallons or greater, the last 500 KWH of use in any month shall be billed at the Storage Water Heating Energy Charge.

	Generation	Transmission	Distribution	Total
Storage Water Heating Energy Charge (¢ per KWH)	2.29537	--	--	2.29537

These provisions, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For purpose of this provision, the on-peak billing period is defined as 7:00 AM to 9:00 PM local time for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays, all hours of the day on Saturdays and Sundays, and the legal holidays of New Year's Day, Presidents Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

The Company reserves the right to inspect at all reasonable times the storage water heating system and devices which qualify the residence for service under the storage water heater provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in its sole judgment the availability conditions of this schedule are being violated, it may discontinue billing the customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Customer Charge as stated in the above monthly rate.

Load Management Water Heating Provision

Availability of this provision is limited to those customers served under this provision as of December 31, 2000.

(Continued on Sheet No. 12-3)

COLUMBUS SOUTHERN POWER
DISTRIBUTION COMPANY

Original Sheet No. 12-3

P.U.C.O. NO. 5

SCHEDULE RLM
(Residential Optional Demand Service)

Load Management Water Heating Provision (Cont'd)

For residential customers who install a Company-approved load management water heating system which consumes electrical energy primarily during off-peak hours specified by the Company and stores hot water for use during on-peak hours, of minimum capacity of 80 gallons, the last 250 KWH of use in any month shall be billed at the Load Management Water Heating Energy Charge.

	Generation	Transmission	Distribution	Total
Load Management Water Heating Energy Charge (¢ per KWH)	2.29537	--	--	2.29537

This provision, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For the purpose of this provision, the on-peak billing period is defined as 7:00 AM to 9:00 PM local time for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays, all hours of the day on Saturdays and Sundays, and the legal holidays of New Year's Day, Presidents' Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

The Company reserves the right to inspect at all reasonable times the load management storage water heating system and devices which qualify the residence for service under the Load Management Water Heating Provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in, its sole judgment, the availability conditions of this schedule are being violated, it may discontinue billing the customer under this provision and commence billing under the standard monthly rate.

Payment

Bills are due and payable in full by mail, checkless payment plan, electronic payment plan or at an authorized payment agent of the Company within 15 days after the mailing of the bill.

Applicable Riders

Monthly Charges computed under this schedule shall be adjusted in accordance with the following applicable riders:

(Continued on Sheet No. 12-4)

Filed pursuant to Order No. 99-xxxx-EL-ETP dated

Issued:

Effective: January 1, 2001

Issued by
Marsha P. Ryan, Vice President
Columbus, Ohio

SCHEDULE RLM
(Residential Optional Demand Service)

Applicable Riders (Cont'd)

Rider	Sheet No.
Universal Service Fund Rider	60-1
Energy Efficiency Fund Rider	61-1
KWH Tax Rider	62-1
Gross Receipts Tax Credit Rider	63-1
Property Tax Credit Rider	64-1
Municipal Income Tax Rider	65-1
Franchise Tax Rider	66-1
Regulatory Asset Charge Rider	67-1

Determination of Billing Demand

The billing demand shall be the maximum 30-minute integrated kilowatt demand recording of an integrating demand meter during the current billing period.

Term of Contract

The term of contract shall be an initial period of four years under the Rural Line Extension Plan, but in no case shall the contract term be less than one year.

Special Term and Conditions

This schedule is subject to the Company's Terms and Conditions of Service.

This schedule is intended for single phase service. Where the residential customer requests three-phase service, this schedule will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service.

Customers with cogeneration and/or small power production facilities shall take service under Schedule COGEN/SPP or by special agreement with the Company.

SCHEDULE RS-ES
(Residential Energy Storage)

Availability of Service

Available for residential customers who use energy storage devices with time-differentiated load characteristics approved by the Company, such as electric thermal storage space heating and/or cooling equipment and water heaters which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours. This schedule shall remain in effect until no later than December 31, 2005.

Households eligible to be served under this schedule shall be metered through one single-phase multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods.

Monthly Rate

	Generation	Transmission	Distribution	Total
Customer Charge ($)	--	--	7.50	7.50
Energy Charge (¢ per KWH):				
For all KWH used during the on-peak billing period	7.17994	1.13233	5.76304	14.07531
For all KWH used during the off-peak billing period	2.29537	--	--	2.29537

On-Peak and Off-Peak Hours

For purpose of this provision, the on-peak billing period is defined as 7:00 AM to 9:00 PM local time for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays, all hours of the day on Saturdays and Sundays, and the legal holidays of New Year's Day, Presidents Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Minimum Charge

(a) The minimum monthly charge for service on lines not subject to the Rural Line Extension Plan shall be the Customer Charge.

(b) The minimum monthly charge for electric service supplied from lines subject to the Rural Line Extension Plan shall, for the initial contract period of four years, be the amount provided in the "Definitions, Rules and Regulations for Rural Line Extension Plan," but in no event shall be less than the Customer Charge.

(Continued on Sheet No. 13-2)

SCHEDULE RS-ES
(Residential Energy Storage)

Conservation and Load Management Credits

For the combination of an approved electric thermal storage space heating and/or cooling system and water heater, all of which are designed to consume electrical energy only during the off-peak period as previously described in this schedule, each residence will be credited the Conservation and Load Management Energy Credit for all KWH used during the off-peak billing period, for a total of 60 monthly billing periods following the installation and use of these devices in such residence.

	Generation	Transmission	Distribution	Total
Conservation and Load Management Energy Credit (¢ per KWH)	0.55570	--	--	0.55570

Separate Metering Provision

Customers shall have the option of receiving service under Schedule R-R or Schedule R-R-1 for their general-use load by separately wiring this equipment to a standard residential meter.

Payment

Bills are due and payable in full by mail, checkless payment plan, electronic payment plan or at an authorized payment agent of the Company within 15 days after the mailing of the bill.

Applicable Riders

Monthly Charges computed under this schedule shall be adjusted in accordance with the following applicable riders:

Rider	Sheet No.
Universal Service Fund Rider	60-1
Energy Efficiency Fund Rider	61-1
KWH Tax Rider	62-1
Gross Receipts Tax Credit Rider	63-1
Property Tax Credit Rider	64-1
Municipal Income Tax Rider	65-1
Franchise Tax Rider	66-1
Regulatory Asset Charge Rider	67-1

Term of Contract

A written agreement may, at the Company's option, be required.

(Continued on Sheet No. 13-3)

SCHEDULE RS-ES
(Residential Energy Storage)

Special Terms and Conditions

This schedule is subject to the Company's Terms and Conditions of Service.

The Company reserves the right to inspect at all reasonable times the energy storage and load management devices which qualify the residence for service and for conservation and load management credits under this schedule, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that, in its sole judgment, the availability conditions of this schedule are being violated, it may discontinue billing the customer under this schedule and commence billing under the appropriate residential schedule.

This schedule is intended for single phase service. Where the residential customer requests three-phase service, this schedule will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service.

Customers with cogeneration and/or small power production facilities shall take service under Schedule COGEN/SPP or by special agreement with the Company.

COLUMBUS SOUTHERN POWER
DISTRIBUTION COMPANY

Original Sheet No. 14-1

P.U.C.O. NO. 5

SCHEDULE RS-TOD
(Residential Time-of-Day Service)

Availability of Service

Available for residential electric service through one single-phase, multi-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods to individual residential customers. Availability is limited to the first 500 customers applying for service under this schedule. This schedule shall remain in effect until no later than December 31, 2005.

Monthly Rate

	Generation	Transmission	Distribution	Total
Customer Charge ($)	–	–	7.50	7.50
Energy Charge (¢ per KWH):				
For all KWH used during the on-peak billing period	7.17994	1.13233	5.76304	14.07531
For all KWH used during the off-peak billing period	2.29537	–	–	2.29537

On-Peak and Off-Peak Hours

For purpose of this provision, the on-peak billing period is defined as 7:00 AM to 9:00 PM local time for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays, all hours of the day on Saturdays and Sundays, and the legal holidays of New Year's Day, Presidents Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Minimum Charge

(a) The minimum monthly charge for service on lines not subject to the Rural Line Extension Plan shall be the Customer Charge.

(b) The minimum monthly charge for electric service supplied from lines subject to the Rural Line Extension Plan shall, for the initial contract period of four years, be the amount provided in the "Definitions, Rules and Regulations for Rural Line Extension Plan," but in no event shall be less than the Customer Charge.

Payment

Bills are due and payable in full by mail, checkless payment plan, electronic payment plan or at an authorized payment agent of the Company within 15 days after the mailing of the bill.

Applicable Riders

Monthly Charges computed under this schedule shall be adjusted in accordance with the following applicable riders:

(Continued on Sheet No. 14-2)

Filed pursuant to Order No. 99-xxxx-EL-ETP dated

Issued:

Effective: January 1, 2001

Issued by
Marsha P. Ryan, Vice President
Columbus, Ohio

SCHEDULE RS-TOD
(Residential Time-of-Day Service)

Applicable Riders (Cont'd)

Rider	Sheet No.
Universal Service Fund Rider	60-1
Energy Efficiency Fund Rider	61-1
KWH Tax Rider	62-1
Gross Receipts Tax Credit Rider	63-1
Property Tax Credit Rider	64-1
Municipal Income Tax Rider	65-1
Franchise Tax Rider	66-1
Regulatory Asset Charge Rider	67-1

Term of Contract

A written agreement may, at the Company's option, be required.

Special Terms and Conditions

This schedule is subject to the Company's Terms and Conditions of Service.

This schedule is intended for single phase service. Where the residential customer requests three-phase service, this schedule will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service.

Customers with cogeneration and/or small power production facilities shall take service under Schedule COGEN/SPP or by special agreement with the Company.

COLUMBUS SOUTHERN POWER
DISTRIBUTION COMPANY

Original Sheet No. 20-1

P.U.C.O. NO. 5

SCHEDULE GS-1
(General Service - Small)

Availability of Service

Available for general service to customers with maximum demands less than 10 KW (excluding the demand served by the Load Management Time-of-Day provision). This schedule shall remain in effect until no later than December 31, 2005.

Monthly Rate

	Generation	Transmission	Distribution	Total
Customer Charge ($)	--	--	6.80	6.80
Energy Charge (¢ per KWH):				
For the first 1,000 KWH used per month	7.18566	0.46025	1.44342	9.08933
For all KWH over 1,000 KWH used per month	4.49566	0.46025	1.44342	6.39933

Minimum Charge

The minimum monthly charge shall be the Customer Charge.

Delayed Payment Charge

The above schedule is net if full payment is received by mail, checkless payment plan, electronic payment plan or at an authorized payment agent of the Company within 21 days after the mailing of the bill. On all accounts not so paid, an additional charge of five percent (5%) of the total amount billed will be made. Federal, state, county, township and municipal governments and public school systems not served under special contract are subject to the Public Authority Delayed Payment provision, Supplement No. 21.

Applicable Riders

Monthly Charges computed under this schedule shall be adjusted in accordance with the following applicable riders:

Rider	Sheet No.
Universal Service Fund Rider	60-1
Energy Efficiency Fund Rider	61-1
KWH Tax Rider	62-1
Gross Receipts Tax Credit Rider	63-1
Property Tax Credit Rider	64-1
Municipal Income Tax Rider	65-1
Franchise Tax Rider	66-1
Regulatory Asset Charge Rider	67-1

(Continued on Sheet No. 20-2)

Filed pursuant to Order No. 99-xxxx-EL-ETP dated

Issued:

Effective: January 1, 2001

Issued by
Marsha P. Ryan, Vice President
Columbus, Ohio

SCHEDULE GS-1
(General Service - Small)

Term of Contract

A written agreement may, at the Company's option, be required.

Special Terms and Conditions

This schedule is subject to the Company's Terms and Conditions of Service.

Customers with cogeneration and/or small power production facilities shall take service under Schedule COGEN/SPP or by special agreement with the Company. A time-of-day meter is required to take service under this provision.

Load Management Time-of-Day Provision

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company, such as electric thermal storage space heating and/or cooling systems and water heaters which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements. A time-of-day meter is required to take service under this provision.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provisions of this schedule.

Monthly Rate

	Generation	Transmission	Distribution	Total
Load Management Customer Charge ($)	–	–	15.15	15.15
Load Management Energy Charge (¢ per KWH):				
For all KWH used during the on-peak billing period	11.37772	1.09402	3.43099	15.90273
For all KWH used during the off-peak billing period	2.74663	–	–	2.74663

For purpose of this provision, the on-peak billing period is defined as 7:00 AM to 9:00 PM local time for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays, all hours of the day on Saturdays and Sundays, and the legal holidays of New Year's Day, Presidents Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

(Continued on Sheet No. 20-3)

SCHEDULE GS-1
(General Service - Small)

Optional Unmetered Service Provision

Available to customers who qualify for Schedule GS-1 and use the Company's service for commercial purposes consisting of small fixed electric loads such as traffic signals and signboards which can be served by a standard service drop from the Company's existing secondary distribution system. This service will be furnished at the option of the Company.

Each separate service delivery point shall be considered a contract location and shall be separately billed under the service contract.

The customer shall furnish switching equipment satisfactory to the Company. The Customer shall notify the Company in advance of every change in connected load, and the Company reserves the right to inspect the customer's equipment at any time to verify the actual load. In the event of the customer's failure to notify the Company of an increase in load, the Company reserves the right to refuse to serve the contract location thereafter under this provision, and shall be entitled to bill the customer retroactively on the basis of the increased load for the full period such load was connected plus three months.

Calculated energy use per month shall be equal to the contract capacity specified at the contract location times the number of days in the billing period times the specified hours of operation. Such calculated energy shall then be billed as follows:

Monthly Rate

	Generation	Transmission	Distribution	Total
Unmetered Service Customer Charge ($)	–	–	4.10	4.10
Unmetered Service Energy Charge (¢ per KWH)	4.46516	0.46025	1.44342	6.36883

This provision is subject to the Terms and Conditions of Schedule GS-1.

SCHEDULE GS-2
(General Service - Low Load Factor)

Availability of Service

Available for general service to customers with maximum demands of 10 KW or greater (excluding the demand served by the Load Management Time-of-Day provision). This schedule shall remain in effect until no later than December 31, 2005.

Monthly Rate

	Generation	Transmission	Distribution	Total
Secondary Voltage:				
Customer Charge ($)	--	--	9.50	9.50
Demand Charge ($ per KW)	--	0.277	3.521	3.798
Off-Peak Excess Demand Charge ($ per KW)	0.313	--	--	0.313
Energy Charge (¢ per KWH)	6.16288	0.38196	--	6.54484
Maximum Energy Charge (¢ per KWH)	6.33438	0.93596	7.04200	14.31234
Primary Voltage:				
Customer Charge ($)	--	--	121.20	121.20
Demand Charge ($ per KW)	--	0.268	2.549	2.817
Off-Peak Excess Demand Charge ($ per KW)	0.303	--	--	0.303
Energy Charge (¢ per KWH)	6.01212	0.37012	--	6.38224
Maximum Energy Charge (¢ per KWH)	8.30822	0.90612	5.09800	14.31234

Minimum and Maximum Charges

Bills computed under the above rate are subject to the operation of minimum and maximum charge provisions as follows:

(a) Minimum Charge - For demand accounts up to 100 KW - the Customer Charge.

For demand accounts over 100 KW - the sum of the Customer Charge, the product of the demand charge and the minimum monthly billing demand and all applicable riders.

(b) Maximum Charge - The sum of the Customer Charge, the product of the Maximum Energy Charge and the metered energy and all applicable riders. This provision shall not reduce the charge specified in the Minimum Charge provision above, (a).

Delayed Payment Charge

The above schedule is net if full payment is received by mail, checkless payment plan, electronic payment plan or at an authorized payment agent of the Company within 21 days after the mailing of the bill. On all accounts not so paid, an additional charge of five percent (5%) of the total amount billed will

(Continued on Sheet No. 21-2)

SCHEDULE GS-2
(General Service - Low Load Factor)

Delayed Payment Charge (Cont'd)

be made. Federal, state, county, township and municipal governments and public school systems not served under special contract are subject to the Public Authority Delayed Payment provision, Supplement No. 21.

Applicable Riders

Monthly Charges computed under this schedule shall be adjusted in accordance with the following applicable riders:

Rider	Sheet No.
Universal Service Fund Rider	60-1
Energy Efficiency Fund Rider	61-1
KWH Tax Rider	62-1
Gross Receipts Tax Credit Rider	63-1
Property Tax Credit Rider	64-1
Municipal Income Tax Rider	65-1
Franchise Tax Rider	66-1
Regulatory Asset Charge Rider	67-1

Monthly Billing Demand

Energy supplied hereunder will be delivered through not more than one single-phase or one polyphase meter. Billing demand in KW shall be taken each month as the single highest 30-minute integrated peak in kilowatts as registered during the month by a 30-minute integrating demand meter or indicator or, at the Company's option, as the highest registration of a thermal-type demand meter or indicator.

The minimum monthly billing demand established hereunder shall not be less than (a) the minimum billing demand, if any, specified in the service contract or (b) 60% of the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 KW.

The minimum monthly billing demand shall not be less than 25% of the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 KW during the billing months of June through September for customers with more than 50% of their connected load used for space heating purposes.

Churches, public and parochial schools, and county, township, municipal and civic recreation centers are subject to the Optional Church and School Service provision, Supplement No. 18.

The Metered Voltage adjustment, as set forth below, shall not apply to the customer's minimum monthly billing demand.

(Continued on Sheet No. 21-3)

SCHEDULE GS-2
(General Service - Low Load Factor)

Optional Time-of-Day Provision

Available to customers who operate primarily during the off-peak period (as set forth below) and request the installation of time-of-day metering in order to receive service under this provision. The customer shall be required to pay the necessary additional metering cost.

For purpose of this provision, the monthly billing demand as defined above shall be determined during the on-peak period. The off-peak excess demand shall be the amount by which the demand created during the off-peak period exceeds the monthly billing demand.

The on-peak billing period is defined as 7:00 AM to 9:00 PM local time for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays, all hours of the day on Saturdays and Sundays, and the legal holidays of New Year's Day, Presidents Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Metered Voltage

The rates set forth in this schedule are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurement taken at the low-side of a customer-owned transformer will be multiplied by 1.01.

(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Term of Contract

For customers with annual average demand greater than 500 KW, contracts will be required for an initial period of not less than one year and shall remain in effect thereafter until either party shall give at least six months written notice to the other of the intention to discontinue service under the terms of this schedule. For customers with demands less than 500 KW, a written agreement may, at the Company's option, be required.

A new initial contract period will not be required for existing customers who increase their contract requirements after the original initial period unless new or additional facilities are required. The Company may, at its option, require a longer initial term of contract to fulfill the terms and conditions of service and/or in order to protect the Company's ability to recover its investment of costs over a reasonable period of time.

(Continued on Sheet No. 21-4)

SCHEDULE GS-2
(General Service - Low Load Factor)

Special Terms and Conditions

This schedule is subject to the Company's Terms and Conditions of Service.

Customers with cogeneration and/or small power production facilities shall take service under Schedule COGEN/SPP or by special agreement with the Company.

This Schedule is also available to customers in the City of Columbus having other sources of energy supply, but who desire to purchase breakdown service from the Company. Where such conditions exist, the customer shall contract for the maximum amount of demand in KW as determined from the customer's connected load or the capacity of transformer and service facilities. Where service is supplied under the provisions of this paragraph, the minimum charge shall be the sum of the Breakdown Service Minimum Demand Charge per KW and the Customer Charge and shall be subject to charges and adjustments under all applicable riders. The customer shall guarantee not to operate the Company's service in parallel with the other source or sources of power supply.

	Generation	Transmission	Distribution	Total
Breakdown Service Minimum Demand Charge ($ per KW)	1.739	0.263	3.710	5.712

Load Management Time-of-Day Provision

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company, such as electric thermal storage space heating and/or cooling systems and water heaters which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements. A time-of-day meter is required to take service under this provision.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provisions of this schedule.

The customer shall be responsible for all local facilities required to take service under this provision.

Monthly Rate

	Generation	Transmission	Distribution	Total
Load Management Customer Charge ($)	--	--	30.10	30.10
Load Management Energy Charge (¢ per KWH):				
For all KWH used during the on-peak billing period	8.94500	0.94671	2.79643	12.68814
For all KWH used during the off-peak billing period	2.52114	--	--	2.52114

(Continued on Sheet No. 21-5)

SCHEDULE GS-2
(General Service - Low Load Factor)

Load Management Time-of-Day Provision (Cont'd)

For purpose of this provision, the on-peak billing period is defined as 7:00 AM to 9:00 PM local time for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays, all hours of the day on Saturdays and Sundays, and the legal holidays of New Year's Day, Presidents Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.