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FILED
APR - 5 1996
MISSOURI
PUBLIC SERVICE COMMISSION

April 3, 1996

UNION ELECTRIC

Mr. David L. Rauch
Executive Secretary
Missouri Public Service Commission
P.O. Box 360
Jefferson City, MO 65102

Re: <u>MPSC Docket No. EM-96-149</u>

Dear Mr. Rauch:

Enclosed please find fifteen (15) copies of revised Schedule 5 to Gary L. Rainwater's Direct Testimony (General Services Agreement) and revised Schedules 4 (Joint Dispatch Agreement) and 6 (System Support Agreement) to Maureen A. Borkowski's Direct Testimony. These revised schedules are executed copies of agreements that were submitted in unexecuted form in UE's initial filing.

Also, please note that Appendix 1 and Appendix 3 of the System Support Agreement have been amended. For the convenience of the Commission and the parties, we have also enclosed marked copies of these Appendices indicating the changes made as compared to those originally attached to Ms. Borkowski's testimony. Specifically these changes include:

<u>Appendix 1</u>: The March and May Contract Firm Capacity values are 350 MW.

<u>Appendix 3</u>: Descriptions of

a) the Transmission Demand Loss factor,
b) Calculation of Seasonal Demand Rates, and
c) Calculation of the monthly Formula Rate, and minor clerical revisions.

Copies of these executed agreements (and the amendments to the Appendices) were made a part of UE's Application to FERC for approval of the UE-CIPSCO merger (EC96-7-000 & ER96-679-000). Consequently, the Missouri Commission and some of the parties to Case No. EM-96-149 have already received copies of these executed agreements.

Enclosed further are fifteen (15) copies of page 1 of revised Schedule 9 of Mr. Rainwater's Direct Testimony.

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The original page 1 contained a minor computational error which has since been corrected (96.6% becomes 93.6%).

Kindly acknowledge receipt and filing of this letter by stamping as filed a copy of this letter and returning it to the undersigned in the enclosed envelope.

Thank you.

Yours very truly,

Joseph H Raybuck

Joseph H. Raybuck
Attorney

JHR:mas
Enclosure(s)

cc: All Parties

MISSOURI PUBLIC SERVICE COMMISSION
Docket No. EM-96-149
Service List
Rev. April 3, 1996

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GENERAL SERVICES AGREEMENT

THIS AGREEMENT, made and entered into this 20th day of December 1995, by and between AMEREN CORPORATION, a Missouri corporation, UNION ELECTRIC COMPANY ("UE"), a Missouri corporation, CENTRAL ILLINOIS PUBLIC SERVICE COMPANY ("CIPS"), an Illinois corporation, and CIPSCO INVESTMENT COMPANY, ("CIC"), an Illinois corporation, referred to collectively as "Parties" and singularly as "Party";

WITNESSETH:

WHEREAS, UE and CIPSCO Incorporated have entered into an Agreement and Plan of Merger, dated August 11, 1995; and,

WHEREAS, pursuant to said Agreement and Plan of Merger a new holding company (AMEREN CORPORATION) will be created, with UE and CIPS as regulated utility subsidiaries, and CIC as a non-utility subsidiary under said new holding company; and,

WHEREAS, to maximize efficiency, and to achieve merger related savings each Party desires to avail itself of the advisory, professional, technical and other services of persons employed or to be retained by the other Parties to this Agreement, and to compensate such other Parties appropriately for such services; and,

WHEREAS, each Party desires to insure that such services are performed economically and efficiently for the benefit of such Parties at cost, fairly and equitably allocated among the Parties.

NOW THEREFORE, in consideration of the mutual undertakings and conditions set forth herein, the Parties agree to do and perform a variety of services for each other, and compensate each other as set forth below:

Section 1. Services to be provided

Except as noted in Section 7, below, each Party shall furnish to any other Party personnel to provide or assist in providing services, as appropriate in the performance of the purposes of the corporations.

Section 2. Payment for services

Except as noted in Section 7, below, for all services performed by the personnel of any Party (Providing Party) for another Party (Receiving Party), the Receiving Party shall reimburse the Providing Party the Cost of Service for all time spent in the performance of such services.

For the purposes of this Agreement, Cost of Service is defined as the total reasonable and necessary compensation paid by the Providing Party to the personnel performing the services for the time so spent, plus an equitable proportion of the reasonable and necessary annual overhead expenses of the Providing Party.

Section 3. Reimbursement of expenses

In addition to the payment for services set out in Section 2 above, the Receiving Party shall reimburse the Providing Party the cost of all expenditures made or incurred by the Providing Party for the Receiving Party's account.

Section 4. Securities and Exchange Commission Rules

It is the intent of the Parties that the determination of the Cost of Service and Expenses as used in this Agreement shall be consistent with, and in compliance with 17 CFR § 250.91, as it now reads or hereafter is modified by the Securities and Exchange Commission.

Section 5. Subsidiary or Mutual Service Company

Should the Parties determine at a later date to form a subsidiary or mutual service company, as contemplated at Section 13 (d) of the Public Utility Holding Company Act of 1935 (15 U.S.C. § 79m), this Agreement will be amended as appropriate, to accommodate such decision, in compliance with all applicable laws and regulations.

Section 6. Payment

Payment shall be by making remittance of the amount billed or by making appropriate accounting entries on the books of the Providing and Receiving Parties.

Payment shall be accomplished no less frequently than on a quarterly basis, and remittance or accounting entries shall be completed within 30 days of billing.

Section 7. Ameren Corporation

Except as authorized by rule, regulation, or order of the Securities and Exchange Commission, nothing in this Agreement shall be read to permit AMEREN CORPORATION, or any person employed by or acting for AMEREN CORPORATION, to provide services for other Parties, or any companies associated with said Parties.

Section 8. Effective Date and Termination

This Agreement is executed subject to the consent and approval of all applicable regulatory agencies, and if so approved in its entirety, shall become effective as of the date the merger between Union Electric and CIPSCO is consummated, and shall remain in effect from said date unless terminated by mutual agreement or by any Party giving at least sixty days' written notice to the other Parties prior to the beginning of any calendar year, each Party fully reserving the right to so terminate the Agreement.

This Agreement may also be terminated to the extent that performance may conflict with any rule, regulation or order of the Securities and Exchange Commission adopted before or after the making of this Agreement.

Section 9. Assignment

This Agreement and the rights hereunder may not be assigned without the mutual written consent of all Parties hereto.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed and attested by their authorized officers as of the day and year first above written.

AMEREN CORPORATION

By [signature]

Title President

ATTEST:

By William E Jaudes

Title Secretary

#4921

UNION ELECTRIC COMPANY

By ______________________

Title Vice President
Corporate Planning

ATTEST:

By ______________________

Title SECRETARY

CENTRAL ILLINOIS PUBLIC SERVICE CO.

By ______________________

Title Vice President - Finance

ATTEST:

By ______________________

Title Assistant Secretary

CIPSCO INVESTMENT COMPANY

By ______________________

Title President

ATTEST:

By ______________________

Title Secretary

#4921

JOINT DISPATCH

AGREEMENT

Between

UNION ELECTRIC COMPANY

AND

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY

JOINT DISPATCH

AGREEMENT

Between

UNION ELECTRIC COMPANY

AND

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY

THIS AGREEMENT is made and entered into this 18th day of December, 1995 by and between UNION ELECTRIC COMPANY ("UE") a Missouri corporation and CENTRAL ILLINOIS PUBLIC SERVICE COMPANY ("CIPS") an Illinois corporation referred to collectively as "Parties" and singularly as "Party," both of whose common stock is wholly owned by Ameren Corporation, hereinafter called "Parent", a Missouri corporation.

WITNESSETH:

WHEREAS, UE and CIPSCO Incorporated, parent company of CIPS, have entered into an Agreement and Plan of Merger, dated August 11, 1995; and

WHEREAS, UE and CIPS are the owners and operators of electric generation, transmission and distribution facilities and are engaged in the business of generating, transmitting, distributing and selling electric energy to the general public, electric utilities, municipalities and cooperatives; and

WHEREAS, to maximize efficiency, and to achieve merger related savings, UE and CIPS will be operated as an integrated control area, will economically commit and dispatch the combined Generating Resources, and will economically utilize power and energy available to the Combined System to transact with other utilities and wholesale entities in order to operate the Combined System in a reliable, efficient, and economic manner; and

WHEREAS, the Parties have entered into a System Support Agreement wherein UE agrees to sell and CIPS agrees to purchase certain quantities of capacity and energy at wholesale.

NOW, THEREFORE, in consideration of the covenants and premises herein set forth, the Parties mutually agree as follows:

ARTICLE I

DEFINITIONS

For the purpose of this agreement, and the Appendices and Service Schedules which are a part hereof, the following definitions shall apply:

1.01 <u>After-the-Fact Resource Allocation</u> shall mean a methodology used to assign the Combined System's Generating Resources and Off-System Power Purchases to each Party's Load Requirements and to the Combined System's Off-System Sales. After-the-Fact Resource Allocation shall be run for each calendar day after the calendar day has transpired.

1.02 <u>Agent</u> shall mean the entity designated to perform certain administrative and coordination functions for the Parties.

1.03 Agreement shall mean this Joint Dispatch Agreement together with all Appendices and Service Schedules applying thereto and any amendments made hereafter.

1.04 Combined System shall mean the combined Generating Resources and transmission facilities of the Parties.

1.05 Control Area shall mean the electric system of UE and CIPS as bounded by interconnection (tie line) metering and telemetry, such that the Generating Resources are controlled directly to maintain the interchange schedule with other control areas and to contribute to frequency regulation of the interconnected system.

1.06 Electric Utility shall mean any entity engaged in the purchase and wholesale sale of electric energy.

1.07 Generating Resources shall mean all power generating facilities owned by a Party available to meet the capacity and energy needs of the Parties. A list of the generating facilities and the owning Party for each facility is included in Appendix 1.

1.08 Generating Unit shall mean an electric generator, together with all auxiliary and appurtenant devices and equipment designed to be operated as a unit for the production of electric power and energy.

1.09 Incremental Cost shall mean any costs incurred by a Party solely by reason of its generation of an incremental amount of energy, which may include but shall not be limited to, costs of fuel, labor, operation, maintenance, start-up, fuel handling, taxes, regulatory commission charges, transmission losses and emissions allowances.

1.10 Load Requirements shall mean the demand and energy which each Party is obligated to serve pursuant to service territory commitments and wholesale requirements agreements, and, in the case of CIPS, that portion of the demand and energy served pursuant to the Soyland and Illinois Municipal Electric Agency (IMEA) power supply agreements which is located in the Control Area. The firm contract capacity and all of the energy set forth in the System Support Agreement shall be included as UE's Load Requirements for purposes of this Joint Dispatch Agreement.

1.11 Net Output shall mean each Party's monthly total of the energy delivered for Load Requirements, less, in the case of CIPS, energy supplied within the Control Area to Soyland and IMEA.

1.12 Off-System Purchases shall mean purchases from a third party of energy and/or associated capacity to reduce costs and/or to provide reliability for the system or as required by law.

1.13 Off-System Sales shall mean all wholesale sales of power and/or energy to third parties outside the Control Area.

1.14 Off-System Sales Margin shall mean the difference between the energy revenue collected from Off-System Sales and the energy cost of providing such sales, as assigned by the After-the Fact Resource Allocation.

1.15 Operating Committee shall mean the organization created under this Agreement to administer its provisions and to undertake the responsibilities set forth in Article VII hereunder.

1.16 Service Schedules shall mean the service schedules attached hereto and those which later may be agreed to by the Parties and accepted for filing by the Federal Energy Regulatory Commission ("FERC").

1.17 Surplus Reserve Ratio shall mean the ratio calculated at the beginning of each month of each Party's surplus reserve to the sum of both Parties' surplus reserve. Surplus reserve shall be calculated for each Party in megawatts by computing the sum of the Party's rated capabilities of its Generating Resources, plus the Party's own non-firm capacity purchases, less its own non-firm capacity sales, less megawatts not available due to scheduled maintenance and long-term forced outages, less 1.15 times the sum of its projected peak demand component of the Load Requirements for the month, plus its firm capacity sales, less its firm capacity purchases.

1.18 System Dispatch shall mean the centralized, economic commitment and dispatch of the Combined System's Generating Resources and Off-System Purchases.

1.19 System Energy Transfer shall mean the transfer of electric energy from one Party's Generating Resources to the other Party to serve the other Party's Load Requirements.

ARTICLE II

TERM OF AGREEMENT

2.01 This Agreement shall take effect as soon as practicable after the merger between UE and CIPSCO Incorporated becomes effective, and shall continue in full force and effect for a minimum of ten years, continuing thereafter until terminated by one or both of the Parties, such Party(ies) having given at least one year's written notice.

2.02 This Agreement will be reviewed periodically by the Operating Committee to determine whether revisions are necessary or appropriate.

ARTICLE III

PURPOSE

The purpose of this Agreement is to provide the contractual basis for coordinated operation of the Combined System to achieve economies consistent with the provision of reliable electric service and an equitable sharing of the benefits and costs of such coordinated operation between the Parties.

ARTICLE IV

AGENT

4.01 Responsibility of the Agent

As soon as practicable after the merger becomes effective, the Parties shall designate an Agent for the purpose of:

a) coordinating the System Dispatch;

b) maintaining the reliability of the Combined System through monitoring and security assessments;

c) arranging and scheduling Off-System Purchases and Off-System Sales;

d) coordinating the provision of transmission service;

e) the development of all bills and billing related information between the Parties and with other transacting entities;

f) operation and maintenance of a central control center to achieve these purposes; and

g) other such activities and duties as may be necessary or as assigned by the Operating Committee.

4.02 Expenses

All expenses incurred by the Agent in the performance of its responsibilities shall be settled in accordance with the arrangements made by the Parties for compensation for services provided between or on behalf of the Parties.

ARTICLE V

COORDINATED OPERATION

5.01 Operation of the Combined System

The Agent shall administer the System Dispatch of the Combined System in order to economically meet the Parties' combined Load Requirements and Off-System Sales obligations, through the economic commitment and dispatch of the Combined System's Generating Resources and Off-System Purchases, consistent with reliable operation of the interconnected system as defined in Article XI. The Agent shall engage in arranging and scheduling economical Off-System Purchases and Off-System Sales, as a single Control Area, utilizing the available generation and transmission resources of the Combined System.

5.02 Communications and Other Facilities

The Parties shall provide communications, metering and other facilities necessary for the metering and control of the Generating Resources and interconnected transmission facilities. Each Party shall be responsible for any expenses it incurs for the installation, operation and maintenance of facilities at its own Generating Units and interconnected transmission facilities. Any expenses incurred due to facilities required at or for the central control center to operate the Combined System shall be settled in accordance with the arrangements made by the Parties for compensation for services provided between and on behalf of the Parties.

ARTICLE VI

ASSIGNMENT OF COSTS AND BENEFITS

OF COORDINATED OPERATIONS

6.01 Fixed Costs of Existing Generating Resources

For all purposes relevant to this Agreement, each Party will retain all costs not collected pursuant to Section 6.07 of its existing Generating Resources that are listed in Appendix 1 attached hereto. Generating unit retirements or permanent derates will be assigned to the Party owning the Generating Unit.

6.02 Environmental Costs of Existing Generating Resources

The cost of environmental compliance (e.g., compliance with the Clean Air Act Amendments of 1990) associated with the existing Generating Resources will be borne by the Party that owns the unit. The Parties will maintain and account for each unit's emissions allowance allocation.

6.03 Demand Charges from Existing Off-System Purchases

Demand Charges from existing Off-System Purchases agreed to as of the effective date of this Agreement, shall remain the responsibility of the Party contracting for the purchase.

6.04 Demand Charges From New Off-System Purchases

Demand charges associated with new Off-System Purchases made to enable the Agent to reliably and economically meet the Parties' combined Load Requirements shall be assigned to the Parties based on the ratio of the demand component (the one hour integrated peak demand) of the Load Requirements of the Parties for the appropriate time period.

Demand charges associated with new Off-System Purchases made to enable the Agent to make new Off-System Sales or to supply existing Off-System Sales shall be deducted from the demand charge revenue collected from the Off-System Sales. The net amount shall be allocated to the Parties pursuant to Sections 6.05 and 6.06.

This section applies only to demand charges associated with new Off-System Purchases made for System Dispatch and not to purchases made by either Party for purposes of maintaining adequate planning reserve margin, which responsibility shall remain with each Party.

6.05 Demand Charges From Existing Off-System Sales

Demand charge revenues collected for existing Off-System Sales, as agreed to as of the effective date of this Agreement, shall remain with the Party contracting for the sale, except that this revenue may be reduced by any demand charges incurred to supply the Off-System Sales pursuant to Section 6.04.

6.06 Demand Charges From New Off-System Sales

Demand charge revenues collected for new Off-System Sales shall be reduced by any demand charges from Off-System Purchases, if any, dedicated to supply the sale, pursuant to Section 6.04. On a monthly basis, the net amount of revenue shall be allocated to the Parties based on the projected monthly Surplus Reserve Ratio.

6.07 Assignment of Energy and Costs From System Dispatch

The Agent shall use After-the-Fact Resource Allocation to assign the energy resources used by the Parties in coordinated operation to each Party and the Off-System Sales. The After-the-Fact Resource Allocation shall be applied consistent with the following principles:

a) Energy from the lowest Incremental Cost generation from each Party's own Generating Resources shall first be assigned to its own Load Requirements.

b) Energy available from Off-System Purchases made by one of the Parties, including existing Off-system Purchases, shall be assigned to the Party who contracted for the purchase, when it is economical. Any energy from Off-System Purchases made by one of the Parties, which the After-the-Fact Resource Allocation does not assign economically to either Party or to Off-System Sales, shall be assigned to the Party who contracted for the purchase. The cost of energy assigned shall be the actual cost of the energy component of the Off-System Purchase.

c) Energy from Generating Resources which are not economical to be operated per System Dispatch but are utilized due to operating constraints shall be allocated to the Party owning the generating unit(s), unless the other

Party's Load Requirements or operating conditions are clearly identified as the reason for the generation, in which case the energy is assigned to the other Party as a System Energy Transfer.

d) Energy from other Off-System Purchases will be assigned to the Parties based on the economics of the purchase. Where a new Off-System Purchase would be economic for both Parties' Load Requirements over the appropriate time period, or is not assigned economically to either Party or to Off-System Sales, the energy from the Off-System Purchase shall be shared between the Parties based on the ratio of the Load Requirements of the Parties. The cost of the energy assigned to each Party shall be the actual cost of the energy component of the Off-System Purchase.

e) Energy from one Party's Generating Resources utilized by the other Party to serve that Party's Load Requirements shall be called System Energy Transfer. Where After-the-Fact Resource Allocation identifies a System Energy Transfer as the source to supply one Party's Load Requirements, the determination of cost for the System Energy Transfer and reimbursement shall be made pursuant to Service Schedule A, System Energy Transfer.

f) Energy from Off-System Purchases may be assigned by the After-the-Fact Resource Allocation or designated by the Agent to be used to supply Off-System Sales. The actual cost of the Off-System Purchase shall be deducted from the energy revenue collected from the Off-System Sale. The net amount shall be included in the calculation of the Off-System Sales Margin.

g) Energy from the Parties' Generating Resources which is not assigned to either Party's Load Requirements shall be assigned to Off-System Sales according to established priorities. The cost of the energy assigned to Off-System Sales shall be the Incremental Cost of the Generating Resources used to supply the sale. This cost shall be deducted from the energy revenue collected from the Off-System Sale. The net amount shall be included in the calculation of Off-System Sales Margin.

6.08 Distribution of the Off-System Sales Margin

The Off-System Sales Margin shall be distributed to the Parties pursuant to Service Schedule B, Distribution of Off-System Sales Margin.

ARTICLE VII

ASSIGNMENT OF TRANSMISSION SERVICE REVENUES

7.01 Revenue from Existing Firm Transmission Service Agreements

Revenue from existing firm transmission service agreements, agreed to as of the effective date of this Agreement, shall remain with the Party contracting for the service. Should an entity receiving service under an existing firm transmission service agreement subsequently take service under the Combined System's Network or Point-to-Point Transmission Service Tariffs, the revenue collected from that service shall be shared between the Parties pursuant to Section 7.03.

7.02 <u>Revenue from Existing Non-Firm Transmission Service Agreements</u>

Revenue from existing non-firm transmission service agreements, agreed to as of the effective date of this Agreement, shall be shared between the Parties pursuant to Section 7.03.

7.03 <u>Revenue from the Combined System's Network and Point-to-Point Transmission Service Tariffs</u>

Revenue from the Combined System's Network and Point-to-Point Transmission Service Tariffs and any other applicable transmission service revenues shall first be assigned to the Parties to reimburse each Party for the cost of any direct assignment facilities or distribution facilities included in the transmission service revenues. The transmission service revenues shall then be used to reimburse either or both of the Parties for any incremental expenses incurred to provide the transmission service, which may include, but shall not be limited to, costs of facility additions, modifications or improvements, uneconomic dispatch costs, losses, and system study costs. The revenue remaining shall be assigned to the Parties in proportion to each Party's Transmission Plant investment relative to the total Transmission Plant investment included in the rate calculation in the Tariffs.

ARTICLE VIII

COMPOSITION AND DUTIES OF THE OPERATING COMMITTEE

8.01 Operating Committee

An Operating Committee shall be the administrative organization of this Agreement and shall consist of four persons, with two members designated by each Party.

8.02 Officers of the Operating Committee

The Operating Committee shall have the following officers with duties as designated:

a) Chairman - The Chairman shall issue calls for and shall preside at meetings of the Operating Committee. The Chairman shall have responsibility for the general coordination of the Operating Committee functions among the members.

b) Vice Chairman - The Vice Chairman shall perform the duties of the Chairman in the Chairman's absence or incapacity.

The Chairman and Vice Chairman shall be appointed from the members of the Operating Committee. The initial Chairman shall be from UE and the initial Vice-Chairman from CIPS, with the Parties alternating those positions thereafter. A new Chairman and Vice-Chairman shall be designated by the Parties at the first meeting held in each odd-numbered calendar year and shall take office immediately upon being appointed.

8.03 Meeting Dates

The Operating Committee shall hold meetings at such times as is appropriate and at any time upon the request of a member of the Operating Committee, but at least once per calendar year. Minutes of each Operating Committee meeting shall be prepared and maintained.

8.04 Decisions

All decisions of the Operating Committee shall be by a majority vote of the members present or voting by proxy at the meeting at which the vote is taken.

8.05 Duties

The Operating Committee shall have the following duties, unless such duties are otherwise assigned by a vote of the Operating Committee to the Agent, in which case the Agent shall perform such duties:

a) Be responsible for the day-to-day administration of this Agreement and the development of any amendments thereto.

b) Review and recommend additional duties and responsibilities for the Agent and review and recommend changes to the procedures for System Dispatch and interchange coordination.

c) Monitor the adequacy of reserves for the Parties and the Combined System.

d) Provide coordination of maintenance schedules for major Generating Resources.

e) Provide coordination for other matters not specifically provided herein which the Parties agree are necessary to operate the Combined System economically.

8.06 Expenses of Committee

Each Party shall pay the expenses of its representatives on the Operating Committee.

ARTICLE IX

BILLING PROCEDURES

9.01 Records

The Agent shall maintain such records as may be necessary to determine the assignment of costs and benefits of coordinated operations pursuant to Article VI of this Agreement. Such records shall be made available to the Parties upon request.

9.02 Monthly Statements

As promptly as practicable after the end of each calendar month, the Agent shall prepare a statement setting forth the monthly summary of the costs and revenues allocated or assigned to the Parties in sufficient detail as may be needed for settlements under the provisions of this Agreement.

In months where both Parties have made System Energy Transfers, only the net cost of the System Energy Transfers need be reflected in the statement.

9.03 Billings and Payments

The Agent shall handle all billing between the Parties and other entities engaging in Off-System Purchases and Off-System Sales with the Parties. In addition to any demand charges or other charges due to one or both of the Parties from the other Party pursuant to agreements other than this Joint Dispatch Agreement, the Agent shall also net bill the Parties, by debiting the Parties as appropriate, and pursuant to Article VI, for:

a) Demand and energy charges for Off-System Purchases, and

b) the cost of System Energy Transfers where the Party was the recipient;

and crediting the Parties, as appropriate, and pursuant to Article VI and VII, for:

a) Demand revenues from Off-System Sales,

b) Off-System Sales Margin,

c) the cost of System Energy Transfers where the Party was the supplier,

d) the Incremental Cost of energy used to supply Off-System Sales where the Party's Generating Resources were used to supply Off-System Sales, and

e) Transmission service revenues;

and shall determine the billing and payment under the System Support Agreement.

All bills will be based on net amounts owed. Payment shall be by making remittance of the amount billed or by making appropriate accounting entries on the books of the Parties.

9.04 Taxes

Should any federal, state, or local tax, in addition to such taxes as may now exist, be levied upon the electric power, energy, or service to be provided in connection with this Agreement, or upon the provider of service as measured by the power, energy, or service, or the revenue therefrom, such additional tax shall be included in the net billing as described in Section 9.03.

ARTICLE X

FORCE MAJEURE

In case either Party should be delayed in or prevented from performing or carrying out any of the agreements, covenants, or obligations made by or imposed upon the Parties by this Agreement, either in whole or in part, by reason of or through strike, work stoppage of labor, failure of contractors or suppliers of materials (including fuel), failure of equipment, environmental restrictions, riot, fire, flood, ice, invasion, civil war, commotion, insurrection, military or usurped power, order of any Court granted in any bona fide adverse legal proceedings or action, or of any civil or military authority either de facto or de jure, explosion, Act of God or the public enemies, or any cause reasonably beyond its control and not attributable to its neglect; then, and in such case or cases, such Party shall not be liable to the other Party for or on account of any loss, damage, injury, or expense resulting from or arising out of such delay or prevention; provided, however, that the Party suffering such delay or prevention shall use due diligence to attempt to remove the cause or causes thereof; and provided, further, that neither Party shall be required by the foregoing provisions to add to, modify, or upgrade any facilities, or to settle a strike or labor dispute except when, according to its own best judgment, such action seems advisable.

ARTICLE XI

INDUSTRY STANDARDS

The Parties agree to conform to all applicable NERC and regional reliability council principles, guides, criteria, and standards and industry standard practices and conventions of reliable system operations.

ARTICLE XII

GENERAL

12.01 No Third Party Beneficiaries

This Agreement is not intended to and shall not create rights of any character whatsoever in favor of any person, corporation, association, entity or power supplier, other than the Parties, and the obligations herein assumed by the Parties are solely for the use and benefit of said Parties. Nothing herein contained shall be construed as permitting or vesting, or attempting to permit or vest, in any person, corporation, association, entity or power supplier, other than the Parties, any rights hereunder or in any of the electric facilities owned by said Parties or the use thereof except as may otherwise be specified herein.

12.02 Waivers

Any waiver at any time by either Party of its right with respect to a default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not be deemed a waiver with respect to any subsequent default or matter. Any delay, short of the statutory period of limitation, in asserting or enforcing any right under this Agreement, shall not be deemed a waiver of such right.

12.03 Successors and Assigns

This Agreement shall inure to the benefit of and be binding upon the Parties only, ard their respective successors and assigns, and shall not be assignable by either Party without the written consent of the other Party except to a successor in the operation of its properties by reason of a merger, consolidation, sale or foreclosure where substantially all such properties are acquired by or merged with such a successor.

12.04 Liability and Indemnification

Subject to any applicable state or federal law which may specifically restrict limitations on liability, each Party shall release, indemnify, and hold harmless the other Party, its directors, officers, and employees from and against any and all liability for loss, damage, or expense alleged to arise from, or incidental to, injury to persons and/or damage to property in connection with its facilities or the production or transmission of electric energy by or through such facilities, or related to performance or nonperformance of this Agreement, including any negligence arising hereunder. In no event shall either Party be liable to the other Party for any indirect, special, incidental, or consequential damages with respect to any claim arising out of this Agreement.

12.05 Governing Law

The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the applicable laws of the State of Missouri.

12.06 Section Headings

The descriptive headings of the Articles and sections of this Agreement are used for convenience only, and shall not modify or restrict any of the terms and provisions thereof.

12.07 Notice

Any notice or demand for performance required or permitted under any of the provisions of this Agreement shall be deemed to have been given on the date such notice, in writing, is deposited in the U.S. mail, postage prepaid, certified or registered mail, addressed to:

UNION ELECTRIC COMPANY
Vice President - Corporate Planning
P. O. Box 149, MC 1400
St. Louis, Missouri 63166

or to:

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY
Vice President - Power Generation
607 East Adams Street
Springfield, Illinois 62739

as the case may be; or in such other form or to such other address as either Party shall stipulate.

ARTICLE XIII

REGULATORY APPROVAL

13.01 Regulatory Authorization

This Agreement shall be subject to the approval of the regulatory agencies having jurisdiction. In the event that this Agreement is not accepted in its entirety by all such agencies, either Party may terminate this Agreement immediately.

13.02 Changes

It is contemplated by the Parties that it may be appropriate from time to time to change, amend, modify or supplement this Agreement or the Schedules which are attached to this Agreement to reflect changes in operating practices or costs of operations or for other reasons. This Agreement may be changed, amended, modified or supplemented by an instrument in writing executed by the Parties.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed and attested by their duly authorized officers on the day and year first above written.

UNION ELECTRIC COMPANY

By ______________________
Vice President

ATTEST:

____
Ass't. Secretary

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY

By G. W. Moorman
Vice President

ATTEST:

____
Secretary

SERVICE SCHEDULE A

SYSTEM ENERGY TRANSFER

Under Joint Dispatch Agreement

between Union Electric Company

and Central Illinois Public Service

A1 - Duration This Service Schedule A shall become effective and binding when the Joint Dispatch Agreement becomes effective, and shall continue in full force and effect throughout the duration of such Agreement. This Service Schedule A is a part of the Agreement and, as such, the use of terms in this Service Schedule A that are defined in the Agreement shall have the same respective meanings as set forth in the Agreement.

A2 - Applicability In accordance with the terms of Articles V and VI of the Agreement, the Combined System's Generating Resources shall be centrally dispatched on an economic dispatch basis which may result in the transfer of electric energy from one Party's Generating Resources to the other Party to serve the other Party's Load Requirements, herein called "System Energy Transfers."

A3 - Compensation Charges for System Energy Transfer shall be the Incremental Cost of the Generating Resources supplying the energy.

UNION ELECTRIC COMPANY

By ______________________
Vice President

CENTRAL ILLINOIS PUBLIC
SERVICE COMPANY

By ______________________
Vice President

SERVICE SCHEDULE B

DISTRIBUTION OF OFF-SYSTEM SALES MARGIN

Under Joint Dispatch Agreement

between Union Electric Company

and Central Illinois Public Service Company

B1 - Duration This Service Schedule B shall become effective and binding when the Joint Dispatch Agreement becomes effective, and shall continue in full force and effect, throughout the duration of such Agreement. This Service Schedule B is a part of the Agreement and, as such, the use of terms in this Service Schedule B that are defined in the Agreement shall have the same respective meanings as set forth in the Agreement.

B2 - Applicability In accordance with the terms of Articles V and VI of the Agreement, the Combined System shall be centrally dispatched on an economic dispatch basis and shall engage in economical Off-System Purchases and Off-System Sales as a single Control Area. The difference between the energy revenue collected from Off-System Sales and the costs of providing such sales, herein called Off-System Sales Margin, is to be distributed between the Parties. This Service Schedule defines the formula for distribution.

B3 - Distribution Formula The monthly distribution ratio for each Party for the Off-System Sales Margin shall be the Party's Net Output divided by the sum of the Parties' Net Output. The amount of Off-System Sales Margin distributed to each Party shall be the Party's monthly distribution ratio times the Off-System Sales Margin.

UNION ELECTRIC COMPANY

By ______________________
Vice President

CENTRAL ILLINOIS PUBLIC
SERVICE COMPANY

By ______________________
Vice President

SERVICE SCHEDULE C

RECOVERY OF INCREMENTAL COSTS RELATING TO EMISSIONS ALLOWANCES

Under Joint Dispatch Agreement

between Union Electric Company

and Central Illinois Public Service Company

C1 - Duration This Service Schedule C shall become effective and binding when the Joint Dispatch Agreement becomes effective, and shall continue in full force and effect throughout the duration of such Agreement. This Service Schedule C is a part of the Agreement and, as such, the use of terms in this Service Schedule C that are defined in the Agreement shall have the same respective meanings as set forth in the Agreement.

C2 - Applicability In accordance with the terms of Articles V and VI of the Agreement, the Combined System shall be centrally dispatched on an economic dispatch basis and shall engage in economical Off-System Purchases and Off-System Sales as a single Control Area. The cost of the energy from the Parties' Generating Resources to supply System Energy Transfer or Off-System Sales is the Incremental Cost of the energy which may include emissions allowance cost. This Service Schedule C defines the methodology for determining the emissions allowance cost.

C3 - Emissions Allowance Recovery Mechanism The emissions allowance cost used in the computation of Incremental Cost shall be the replacement cost of emissions allowances. The emissions allowance replacement cost will be the "Monthly Price Index" published by Cantor Fitzgerald Environmental Brokerage Service by the twenty-fifth day of the month prior to the month the transaction occurs. The Parties will use the Cantor Fitzgerald index unless one or both of the Parties is involved in the actual purchase or sale of allowances wherein it may choose at its option to use the price of its own transactions, such transactions to have a minimum allowance quantity of 1,000 allowances. Although the Parties have designated Cantor Fitzgerald as the index to be used in establishing emissions allowance cost, the Parties will continue to evaluate other market indicators. The Parties may in the future designate another index to serve as the incremental price indicator.

The allowance replacement cost, in $/$SO_2$ ton, will be used to calculate a Generating Unit's incremental SO_2 cost as described below. The incremental SO_2 cost of operating an affected unit will be calculated using three components—the allowance replacement cost, the unit's incremental heat rate and the SO_2 rate of the fuel used at the unit.

$$EC = \frac{AC \times HR \times SR}{2 \times 10^6}$$

Where: EC = Total Incremental SO_2 Cost (\$/Mwh)

AC = Allowance Replacement Cost (\$/SO_2 Ton)

HR = Incremental Heat Rate (Btu/Kwh)

SR = SO_2 Rate for Fuel (Lbs of SO_2/MMbtu)

The incremental emissions cost (EC) will be used to dispatch generating units, make Off-System Purchase and Off-System Sales decisions, and price System Energy Transfers, pursuant to this Agreement. The Generating Unit used to compute the emissions allowance amount will be the same unit that is used to calculate the Incremental Cost.

Either Party will have the option to pay the allowance replacement cost or provide equivalent emissions allowances. Cash payment will be due in accordance with the terms and conditions of this Agreement. If a Party elects to provide emissions allowances, the equivalent emissions allowances will be calculated as follows:

$$\text{Allowances Due} = \frac{TEC}{AC}$$

Where: TEC = Total Monthly Emissions Allowance Replacement Cost ($)

AC = Allowance Replacement Cost ($/$SO_2$ Ton)

The Parties do not intend to round the number of allowances due to the nearest whole number. Any fractional emissions allowances will be settled on a cash basis. The allowances due must be the current year's vintage and be transferred to an account designated by each Party by December 31 of that year. Each Party will be reimbursed by the other for any additional costs incurred to replace emissions allowances plus any penalties assessed by the Environmental Protection Agency due to failure of one Party to transfer any required emissions allowances by December 31.

UNION ELECTRIC COMPANY

By ________________
Vice President

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY

By ________________
Vice President

SYSTEM SUPPORT

AGREEMENT

BETWEEN

UNION ELECTRIC COMPANY

AND

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY

SYSTEM SUPPORT AGREEMENT

THIS SYSTEM SUPPORT AGREEMENT (hereinafter called "Agreement"), made and entered into this 18th day of December, 1995, by and between UNION ELECTRIC COMPANY, a corporation organized and existing under the laws of the State of Missouri (hereinafter called UE) and CENTRAL ILLINOIS PUBLIC SERVICE COMPANY, a corporation organized and existing under the laws of the State of Illinois (hereinafter called CIPS), referred to collectively as "Parties" and singularly as "Party," both of whose common stock is wholly owned by Ameren Corporation, hereinafter called "Parent," a Missouri corporation.

WITNESSETH THAT:

WHEREAS, UE and CIPS are engaged in the business of generating, purchasing, transmitting, distributing and selling electric power and energy; and

WHEREAS, UE and CIPSCO Incorporated, parent of CIPS have entered into an Agreement and Plan of Merger, dated August 11, 1995 which, in part, provides for the transfer of UE's Illinois retail electric and gas properties to CIPS; and

WHEREAS, CIPS and UE, along with Illinois Power Company ("IP"), are parties to an Interconnection Agreement between CIPS, IP and UE ("Ill-Mo Pool Agreement") dated August 15, 1952, amended in its entirety on February 18, 1972 and as amended thereafter; and

WHEREAS, pursuant to the transfer of UE's Illinois retail properties to CIPS, UE agrees to sell and CIPS agrees to purchase certain quantities of capacity and energy at wholesale; and

WHEREAS, the Parties have entered into a Joint Dispatch Agreement in order to coordinate the operation of the combined system to achieve economies consistent with the provision of reliable electric service;

NOW, THEREFORE, UE and CIPS, in consideration of the mutual promises and covenants herein contained, do hereby agree as follows:

ARTICLE 1 TERM OF AGREEMENT

The effective date of this Agreement shall be the date when the merger between UE and CIPSCO Incorporated becomes effective, and shall continue in full force and effect for a minimum of thirty years.

ARTICLE 2 PURPOSE

The purpose of this Agreement is to set forth the contractual terms and conditions for the sale of capacity and energy by UE to CIPS related to the transfer of UE's Illinois retail electric properties to CIPS.

ARTICLE 3 UE'S OBLIGATIONS TO DELIVER POWER

3.1 Contract Capacity and Energy

UE shall make capacity and energy available to CIPS under this Agreement in the quantities set forth in Appendix 1 attached hereto, subject to the terms and conditions set forth herein. The contract capacity shall include amounts for both firm capacity and interruptible capacity.

3.2 Capacity Planning

UE agrees that it will provide capacity and reserves for and maintain facilities capable of delivering the firm capacity provided for in Appendix 1. In planning for reserves, UE shall treat the firm capacity obligation under this Agreement as if it were a part of its firm native load. UE shall not be obligated to plan for capacity or reserves for the interruptible capacity provided under this Agreement.

3.3 Delivery

Capacity and energy to be delivered under this Agreement shall be delivered at CIPS' points of connection with UE as defined in the Ill-Mo Pool Agreement, as modified to account for the transfer of UE's Illinois retail electric properties to CIPS. The primary points of delivery shall be the connections between UE and CIPS established pursuant to the transfer of UE's Illinois retail electric properties to CIPS.

3.4 Curtailment of Capacity and Energy

The delivery of any portion or all of the interruptible capacity and energy provided to CIPS under this Agreement may be curtailed at any time, subject to the following conditions: when it is anticipated that the combined UE and CIPS system annual peak will be established or whenever, in the judgment of the control area operator, which is specified in the Joint Dispatch Agreement, such power is required to a) maintain a firm power supply to non-interruptible customers; b) meet contractual obligations for the delivery of firm power to other utilities; c) maintain water elevation levels at UE's hydro plants consistent with the preservation of desired system reliability levels and applicable regulatory operating requirements; d) prevent jeopardizing the interconnected generation and transmission system.

Delivery of the firm capacity and energy provided to CIPS under this Agreement may be curtailed, but only in the event of and in proportion to the curtailment of UE's firm retail and firm wholesale load. CIPS shall receive as much advance notice as practicable from the control area operator in the event that curtailment of firm capacity and energy becomes probable.

ARTICLE 4 ENERGY DISPATCH

4.1 Hourly Profile

In order to account for the delivery of the contract capacity and energy under this Agreement as provided in Section 3.1 and set forth in Appendix 1, the Parties agree to develop an hourly profile of megawatthours to be delivered in each hour of the day. Such profile will be used for each day of a given calendar month but shall be changed monthly. The sum of the hourly megawatthour amounts for all days in any calendar month shall equal the contract energy amounts for that month. In no event shall the maximum amount of megawatthours included in the hourly profile for any given hour exceed the sum of the contract firm capacity and the contract interruptible capacity.

4.2 Joint Dispatch

Since under the Joint Dispatch Agreement executed by the Parties, the Parties will operate as a single control area, the hourly profiles developed pursuant to Section 4.1 shall be used to establish the Load Requirements used in the After-the-Fact Resource Allocation described in the Joint Dispatch Agreement.

ARTICLE 5 RATES FOR SERVICE

5.1 Demand Charges

The rate which CIPS shall pay to UE for capacity during the term of this Agreement shall be developed according to the formula included in Appendix 3, attached hereto. This formula shall be calculated annually (the "formula rate") and the formula rate shall be applied to the contract capacity values for the appropriate month as listed in Appendix 1 or as modified pursuant to Section 5.3, with the new rates and any new contract capacity value effective beginning in June of each year. The contract firm capacity shall be billed at the formula rate. The contract interruptible capacity shall be billed at one-half of the formula rate.

Included in the formula rate in Appendix 3 is a component for return on common equity. The Parties agree to fix the return on common equity in the formula rate at 12.26% for the initial five years following the effective date of this Agreement. Thereafter, this rate may be renegotiated by the Parties pursuant to Section 10.2 if either of the two following conditions occurs: (1) the first mortgage bonds of Union Electric Company are rated BBB+ or lower by Standard & Poor's; or (2) the yield on Moody's A-rated Utility Bond Index is less than 6.75% or greater than 9.75%.

5.2 Energy Charges

The rate which CIPS shall pay to UE for energy during the term of this Agreement shall be developed according to the formula included in Appendix 4, attached hereto. This formula shall be calculated annually (the "formula energy rate") and the formula energy rate shall be applied to the contract energy values for the appropriate month as listed in Appendix 1 or as modified pursuant to Section 5.3, with the new rates and any new contract energy values effective beginning in June of each year. The

Parties agree to perform an annual reconciliation of the actual costs for the previous year and to adjust the formula energy rate to reflect the difference in actual versus billed costs for the previous year in the formula energy rate for the coming year.

5.3 Billing Units

As described in Sections 5.1 and 5.2, the billing units to be applied to the formula rate and the formula energy rate are the contract capacity and energy values set forth in Appendix 1. There will be no metered billing units for purposes of this Agreement.

In the event that UE retires any one or more of the generating units listed in Appendix 2, the contract capacity (firm and interruptible) values and contract energy values set forth in Appendix 1 shall be adjusted downward by an amount proportional to the reduction in net summer capability, calculated by the ratio of the net summer capability of the retired unit(s) to the total net summer capability listed in Appendix 2. Adjustments to contract capacity values shall be rounded to the nearest whole megawatt. Adjustments to contract energy values shall be rounded to the nearest million of kilowatt-hours.

ARTICLE 6 BILLING

All billing for service rendered by UE to CIPS under this Agreement shall be made pursuant to Article IX of the Joint Dispatch Agreement. All provisions included in

Article IX of the Joint Dispatch Agreement shall apply in full force and effect to this Agreement. In the event that the Joint Dispatch Agreement is terminated, or amended in a manner that substantively affects Article IX, while this Agreement is still in effect, the Parties agree to make reasonable provisions for timely billing and payment for service under this Agreement.

ARTICLE 7 FORCE MAJEURE

In case either Party should be delayed in or prevented from performing or carrying out any of the agreements, covenants, or obligations made by or imposed upon the Parties by this Agreement, either in whole or in part, by reason of or through strike, work stoppage of labor, failure of contractors or suppliers of materials (including fuel), failure of equipment, environmental restrictions, riot, fire, flood, ice, invasion, civil war, commotion, insurrection, military or usurped power, order of any Court granted in any bona fide adverse legal proceedings or action, or of any civil or military authority either de facto or de jure, explosion, Act of God or the public enemies, or any cause reasonably beyond its control and not attributable to its neglect; then, and in such case or cases, such Party shall not be liable to the other Party for or on account of any loss, damage, injury, or expense resulting from or arising out of such delay or prevention; provided, however, that the Party suffering such delay or prevention shall use due and, in its judgment, practicable diligence to attempt to remove the cause or causes thereof; and provided, further, that neither Party shall be required by the foregoing provisions to add to, modify, or upgrade any facilities, or to settle a strike or labor dispute except when, according to its own best judgment, such action seems advisable.

ARTICLE 8 INDUSTRY STANDARDS

The Parties agree to conform to all applicable NERC and regional reliability council principles, guides, criteria, and standards and industry standard practices and conventions of reliable system operations.

ARTICLE 9 GENERAL

9.1 No Third Party Beneficiaries

This Agreement is not intended to and shall not create rights of any character whatsoever in favor of any person, corporation, association, entity or power supplier, other than the Parties, and the obligations herein assumed by the Parties are solely for the use and benefit of said Parties. Nothing herein contained shall be construed as permitting or vesting, or attempting to permit or vest, in any person, corporation, association, entity or power supplier, other than the Parties, any rights hereunder or in any of the electric facilities owned by said Parties or the use thereof except as may otherwise be specified herein.

9.2 Waivers

Any waiver at any time by either Party of its right with respect to a default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not be deemed a waiver with respect to any subsequent default or matter. Any delay, short of the statutory period of limitation, in asserting or enforcing any right under this Agreement, shall not be deemed a waiver of such right.

9.3 Successors and Assigns

This Agreement shall inure to the benefit of and be binding upon the Parties only, and their respective successors and assigns, and shall not be assignable by either Party without the written consent of the other Party except to a successor in the operation of its properties by reason of a merger, consolidation, sale or foreclosure where substantially all such properties are acquired by or merged with such a successor.

9.4 Liability and Indemnification

Subject to any applicable state or federal law which may specifically restrict limitations on liability, each Party shall release, indemnify, and hold harmless the other Party, its directors, officers, and employees from and against any and all liability for loss, damage, or expense alleged to arise from, or incidental to, injury to persons and/or damage to property in connection with its facilities or the production or transmission of electric energy by or through such facilities, or related to performance or nonperformance of this Agreement, including any negligence arising hereunder. In no event shall either Party be liable to the other Party for any indirect, special, incidental, or consequential damages with respect to any claim arising out of this Agreement.

9.5 Governing Law

The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the applicable laws of the State of Missouri.

9.6 Section Headings

The descriptive headings of the Articles and sections of this Agreement are used for convenience only, and shall not modify or restrict any of the terms and provisions thereof.

9.7 Notice

Any notice or demand for performance required or permitted under any of the provisions of this Agreement shall be deemed to have been given on the date such notice, in writing, is deposited in the U.S. mail, postage prepaid, certified or registered mail, addressed to:

UNION ELECTRIC COMPANY

Vice President - Corporate Planning

P. O. Box 149, MC 1400

St. Louis, Missouri 63166

or to:

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY

Vice President - Power Generation

607 East Adams Street

Springfield, Illinois 62739

as the case may be; or in such other form or to such other address as either Party shall stipulate.

ARTICLE 10 REGULATORY APPROVAL

10.1 Regulatory Authorization

This Agreement shall be subject to the approval of the regulatory agencies having jurisdiction. In the event that this Agreement is not accepted in its entirety by all such agencies, the Parties agree to make such modifications as may be necessary to receive such acceptance, while preserving the purpose set forth in Article 2.

10.2 Changes

It is contemplated by the Parties that it may be appropriate from time to time to change, amend, modify or supplement this Agreement or the Appendices which are attached to this Agreement to reflect changes in operating practices, costs, or for other reasons. Such changes may include, but are not limited to, reductions in the contract capacity and energy to reflect significant loss of load in the Illinois retail electric territory transferred to CIPS or changes in the formula rates for demand and energy, as circumstances may warrant, in order to avoid the creation of an undue economic burden on either Party. This Agreement may be changed, amended, modified or supplemented by an instrument in writing executed by the Parties.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed and attested by their duly authorized officers on the day and year first above written.

UNION ELECTRIC COMPANY

By ______________________
Vice President

ATTEST:

____
Ass't Secretary

CENTRAL ILLINOIS PUBLIC
SERVICE COMPANY

By ______________________
Vice President

ATTEST:

____
Secretary

APPENDIX 1

CONTRACT CAPACITY AND ENERGY

	Contract Firm Capacity (MW)	Contract Interruptible Capacity (MW)	Contract Energy (Millions of kWh)
January	400	85	300
February	400	85	300
March	350	85	300
April	350	85	280
May	350	85	280
June	450	70	320
July	500	70	320
August	500	70	320
September	450	70	320
October	350	85	280
November	350	85	280
December	400	85	300

Appendix 2

GENERATING CAPABILITY		
Union Electric Company		
Station Name & Unit No.	*Unit Type*	*Net Summer Capability (MW)*
Callaway	Nuclear	1125
Canton Diesels (5 units)	Internal Combustion	4
Fairgrounds Comb. Turbine	Combustion Turbine	55
Howard Bend Comb. Turbine	Jet Engine	43
Keokuk (15 units)	Hydro	119
Kirksville Comb. Turbine	Combustion Turbine	13
Labadie 1	Steam	559
Labadie 2	Steam	559
Labadie 3	Steam	559
Labadie 4	Steam	559
Meramec 1	Steam	131
Meramec 2	Steam	131
Meramec 3	Steam	280
Meramec 4	Steam	338
Meramec Comb. Turbine	Combustion Turbine	55
Mexico Comb. Turbine	Combustion Turbine	55
Moberly Comb. Turbine	Combustion Turbine	55
Moreau Comb. Turbine	Combustion Turbine	55
Osage (8 units)	Hydro	212
Portable Diesel	Internal Combustion	1
Rush Island 1	Steam	581
Rush Island 2	Steam	581
Sioux 1	Steam	463
Sioux 2	Steam	463
Taum Sauk (2 units)	Pumped Storage	350
Venice (6 units)	Steam	429
Venice Comb. Turbine	Combustion Turbine	25
Viaduct Comb. Turbine	Combustion Turbine	25
TOTAL		7825

APPENDIX 3
FORMULA RATE
FOR DEMAND RELATED CHARGES
(PAGE CITES REFER TO FERC FORM 1 DATA)

PRODUCTION

A. Total Power Production Expense (p. 321.80b)
B. Purchased Power Energy Expense (p. 327B.14k)
Energy Related O & M
Steam
- Fuel (p.320.5b)
- Steam Expenses (p.320.6b)
- Maintenance Supervision & Engineering (p.320.15b)
- Maintenance of Boiler Plant (p. 320.17b)
- Maintenance of Electric Plant (p.320.18b)

Nuclear
- Fuel (p320.25b)
- Maintenance Supervision & Engineering (p.320.35b)
- Maintenance of Reactor Plant Equipment (p. 320.37b)
- Maintenance of Electric Plant (p. 320.38b)

Hydraulic
- Maintenance of Electric Plant (p.321.56b)

Other
- Fuel (p. 321.63b)

C. Total Energy Related O & M (Sum)

D. Sales For Resale Energy Revenue (p311C.12i)
E. Sales For Resale Demand Revenue (p311C.12h)
F. Total Production Plant Investment (p. 207.42g)

PRODUCTION O & M - FCR = $\frac{A-B-C+D-E}{F}$

TRANSMISSION

A. Total Transmission Expenses (p. 321.100b)
B. Transmission By Others (p. 321.88b)
C. Total Transmission Plant Investment (p. 207.53g)

TRANSMISSION O & M - FCR = $\frac{A-B}{C}$

OTHER TAXES EXPENSE

X. Other Taxes (Electric Only) (p.115.13e less [p.263.25i,.26i,.27i,.28i,.41i and 263A.53i,.54i, & .55i])
Y. Electric Plant in Service (p. 207.88g)

OTHER TAXES - FCR = $\frac{X}{Y}$

A & G EXPENSE

A. Production Wages Expense (p.354.18b)
B. Transmission Wages Expense (p. 354.19b)
C. A & G Wages Expense (p. 354.24b)
D. Total Wages Expense (p. 354.25b)
E. Total A & G Related O & M (p. 323.168b)
P. Total Production Plant Investment (p. 207.42g)
T. Total Transmission Plant Investment (p. 207.53g)

PRODUCTION A & G - FCR = A/(D-C) * E/P

TRANSMISSION A & G - FCR = B/(D-C) * E/T

DEPRECIATION EXPENSE

DEp = Production Depreciation Expense =
(Sum of p. 336.2b-336.6b less Total Nuclear Decommissioning Expense)
DEt = Transmission Depreciation Expense (p.336.7b)
DEg - General Plant Depreciation Expense(p336.9b)
P = Total Production Plant Investment (p. 207.42g)
T = Total Transmission Plant Investment (p. 207.53g)
G - Total General Plant Investment (p207.83g)

Production Depreciation

SLDp = $\frac{DEp}{P}$

n(depreciable years)= $\frac{1}{SLDp}$

PRODUCTION DEPRECIATION - FCR =
SFDp = $\frac{ROR}{(1+ROR)^n - 1}$

Transmission Depreciation

$$SLDt = \frac{DEt}{T}$$

$$n(\text{depreciable years}) = \frac{1}{SLDt}$$

TRANSMISSION DEPRECIATION - FCR =

$$SFDt = \frac{ROR}{(1+ROR)^{n} - 1}$$

General Plant Depreciation

$$SLDg = \frac{DEg}{G}$$

$$n(\text{depreciable years}) = \frac{1}{SLDg}$$

General Plant Depreciation - FCR =

$$SFDg = \frac{ROR}{(1+ROR)^{n} - 1}$$

Where:

RATE OF RETURN
Component @ year end for historical period

	Ratio	Cost Rate	Weighted Cost
Long Term Debt	A	AR	A*AR
Preferred Stock	B	BR	B*BR
Common Stock	C	CR	C*CR
Totals:	100.00%		

ROR = Sum of Weighted Cost

RATE OF RETURN ADJUSTED TO GROSS PLANT

PRODUCTION
A. Total Production Plant Investment (p. 207.42g)

B. Accum. Prov. for Depr. (Sum of p.219.18c - 22c)

C. Net Production Plant (A-B)

PRODUCTION ROR(A) = $\frac{C}{A}$ * ROR

TRANSMISSION

A. Total Transmission Plant Investment (p. 207.53g)

B. Accum. Prov. for Depr. (p.219.23c)

C. Net Transmission Plant (A-B)

TRANSMISSION ROR(A)= $\frac{C}{A}$ * ROR

GENERAL

A. Total General Plant Investment (p. 207.83g)

B. Accum. Prov. for Depr. (p.219.25c)

C. Net General Plant (A-B)

GENERAL ROR(A) = $\frac{C}{A}$ * ROR

COMPOSITE INCOME TAX EXPENSE

CIT - FCR = (.385)/(1-.385)*(ROR(A)+SFD-SLD)*(1-Wtd. LTD/ROR(A))

PRODUCTION CIT - FCR = >
TRANSMISSION CIT - FCR = > (as per formula)
General Plant CIT - FCR = >

GENERAL PLANT

A. Production Wages Expense (p.354.18b))
B. Transmission Wages Expense (p 354.19b)
C. A & G Wages Expense (p354.24b)
D. Total Wages Expense (p 354.25b)
E. Total General Plant Investment (p207.83g)
P. Total Production Plant Investment (p.207.42g)
T. Total Transmission Plant Investment (p 207.53g)

PRODUCTION PLANT GENERAL PLANT FACTOR

G. A/(D-C)
H. General Plant (DEPR + CIT+ Other Taxes+ROR(A))
I. Total General Plant Investment (p207.83g)
J. General Plant Revenue Requirement (H*I)
K. Production Related General Plant (G*J)

PRODUCTION GENERAL PLANT FACTOR - FCR = K / P

TRANSMISSION PLANT GENERAL PLANT FACTOR

V. B/(D-C)
J. General Plant Revenue Requirement (H * I)
M. Transmission Related General Plant(V * J)

TRANSMISSION GENERAL PLANT FACTOR - FCR = M / T

CASH WORKING CAPITAL

A. Total Production Expense (p 321.80b)
B. Total Transmission Expense (p 321.100b)
C. Total Electric O & M Expenses (p 323.169b)
D. Total Prepayments (p 110.45d)
P. Total Production Plant Investment (p207.42g)
T. Total Transmission Plant Investment (p 207.53g)

PRODUCTION PLANT CASH WORKING CAPITAL - FCR =

$$\frac{A*D}{C*P} *(ROR-((Wtd.LTD)*.385))/(1-.385)$$

TRANSMISSION PLANT CASH WORKING CAPITAL - FCR =

$$\frac{B*D}{C*T} *(ROR-((Wtd.LTD)*.385))/(1-.385)$$

MATERIALS AND SUPPLIES

PRODUCTION

A. Fuel Stock (p.227.1b & 1c [avg.])
B. Materials & Supplies (p227.7b &7c [avg.])
C. Total Production Plant Investment (p.207.42g)

PRODUCTION MATERIALS & SUPPLIES - FCR =

$$\frac{(A+B)}{C} *(ROR-((Wtd.LTD)*.385))/(1-.385)$$

TRANSMISSION

A. Materials & Supplies (p227.8b & 8c [avg.])
B. Total Transmission Plant Investment (p.207.53g)

TRANSMISSION MATERIALS & SUPPLIES - FCR =

$$\frac{A}{B} *(ROR-((Wtd.LTD)*.385))/(1-.385)$$

ACCUMULATED DEFERRED INCOME TAXES

A. Electric Plant in Service(p207.88g)
B. Account 190(p234.8c)
C. Account 282(p275.2k)

D. COSS Factor = Ratio of ADIT remaining after deductions for certain ADIT deducted from Rate Base and treated as non-operating income divided by (C - B)

E. Production Factor = Proportion of ADIT related to Production

PRODUCTION [ADIT] = $\frac{B-C}{A} * D * E$

F. Transmission Factor = Proportion of ADIT related to Transmission

TRANSMISSION [ADIT] = $\frac{B-C}{A} * D * F$

FIXED CHARGE RATE CALCULATION

		PRODUCTION	TRANSMISSION
(1) Operation & Maintenance Expense	>		
(2) Other Taxes	>		
(3) Administrative & General Expense	>		
(4) Return - ROR(A)	>		
(5) SFD Depreciation	>	(as calculated per previous pages)	
(6) Composite Income Tax	>		
(7) General Plant	>		
(8) Cash Working Capital	>		
(9) Material and Supplies	>		
(10) [ADIT] *((4) + (6) above)	>		
FIXED CHARGE RATE		Sum of (1) through (10)	

PRODUCTION

A. INVESTMENT TOTAL PRODUCTION PLANT (p. 207.42g)

B. ANNUAL REVENUE REQUIREMENT = FCR * A

C. DEMAND UNITS (in kW) =(Average of p.401.29(d) through 40(d))
less (.5 * the average of the monthly UE system coincident interruptible demands)

PRODUCTION DEMAND RATE (per kW - year) = $\frac{B}{C}$

TRANSMISSION

A. INVESTMENT TOTAL TRANSMISSION PLANT (p. 207.53g)

B. ANNUAL REVENUE REQUIREMENT = FCR * A

C. TRANSMISSION DEMAND LOSS FACTOR = (1-TRANSMISSION DEMAND LOSS MULTIPLIER)

D. ADJUSTED ANNUAL REVENUE REQUIREMENT= B / C

E. DEMAND UNITS (in kW) =(Average of p.401.29(d) through 40(d))
less (.5 * the average of the monthly UE system coincident interruptible demands)

TRANSMISSION DEMAND RATE (per kW -year) = $\frac{D}{E}$

CALCULATION OF SEASONAL PRODUCTION AND TRANSMISSION DEMAND RATES

A. ANNUAL PRODUCTION AND TRANSMISSION DEMAND RATE : Sum of Demand Rates calculated above

B. SEASONAL RATES:

WINTER RATE (January through May and October through December) = WR
SUMMER RATE (June through September) = 1.7 * WR

C. SEASONAL RATE CALCULATION (Demand data from Appendix 1)

WR * (Sum of the Firm Winter Demands + .5 * Sum of the Interruptible Winter Demands)
+ 1.7 * WR * (Sum of the Firm Summer Demands + .5 * Sum of the Interruptible Summer Demands)
= A * (Average of the Firm Demands + .5 * Average of the Interruptible Demands)

WINTER RATE (per kW- month) =	as calculated above
SUMMER RATE (per kW- month) =	1.7 * Winter Rate

NUCLEAR DECOMMISSIONING EXPENSE

(Initally set at $425,000. Thereafter, to be updated every third year consistent with the following formula, beginning in the year 2000.)

A. ANNUAL REVENUE REQUIREMENT:
(based on study defining the amount necessary for appropriate funding)
B. DEMAND UNITS (in kW) = (Sum of the Firm Demands
+ .5 * the Sum of the Interruptible Demands from Appendix 1)

NUCLEAR DECOMMISSIONING CHARGE = (per kW - month) $\frac{A}{B}$

(To be added to each monthly Demand Rate as calculated above)

CALCULATION OF THE MONTHLY FORMULA DEMAND RATE

The monthly formula demand rate is the sum of the appropriate Seasonal Demand Rate plus the Nuclear Decommissioning Charge. The monthly demand charge is the sum of the monthly formula demand rate times the Firm Demand plus .5 times the monthly formula demand rate times the Interruptible Demand. (All demand data from Appendix 1.)

APPENDIX 4

FORMULA RATE

FOR ENERGY RELATED CHARGES

	FERC FORM 1 Reference (Page . Line)
Energy-Related O&M	
Steam Power	
Fuel	P.320.5b
Steam Expenses	P.320.6b
Maintenance Supervision & Engineering	P.320.15b
Maintenance of Boiler Plant	P.320.17b
Maintenance of Electric Plant	P.320.18b
Nuclear	
Fuel	P.320.25b
Maintenance Supervision & Engineering	P.320.35b
Maintenance of Reactor Plant Equipment	P.320.37b
Maintenance of Electric Plant	P.320.38b
Hydraulic	
Maintenance of Electric Plant	P.321.56b
Other	
Fuel	P.321.63b
TOTAL (A)	Sum
Purchased Power Energy Expense (B)	P.327B.14k
Sales For Resale Energy Revenue (C)	P.311C.12i
Sales (MWh)	
Ultimate Consumer	P.401.22b
Sales for Resale	P.401.23b
Total Sales (D)	Sum

$$\text{Energy Rate (in \$ per MWh)} = \frac{A + B - C}{D}$$

WORKPAPERS

Production

A. Total Power Production Expense (p. 321.80b)		$718,594,4
B. Purchased Power Energy Expense (p. 327B.14k)		$125,238,5
C. Energy Related O & M		
Steam		
Fuel (p. 320.5b)	$286,188,076	
Steam Expenses (p. 320.6b)	$9,123,511	
Maintenance Supervision & Engineering (p. 320.15b)	$6,958,786	
Maintenance of Boiler Plant (p. 320.17b)	$52,207,154	
Maintenance of Electric Plant (p. 320.18b)	$19,362,782	
Nuclear		
Fuel (p. 320.25b)	$52,351,999	
Maintenance Supervision & Engineering (p. 320.35b)	$3,990,021	
Maintenance of Reactor Plant Equipment (p. 320.37b)	$7,123,022	
Maintenance of Electric Plant (p. 320.38b)	$4,223,108	
Hydraulic		
Maintenance of Electric Plant (p. 321.56b)	$722,347	
Other		
Fuel (p. 321.63b)	$1,293,755	
C. Total Energy Related O & M (Sum)	$443,544,561	$443,544,56
D. Sales For Resale Energy Revenue (p. 311C.12i)	$139,134,079	
E. Sales For Resale Demand Revenue (p. 311c.12h)	$28,687,691	
F. Total Production Plant Investment (p. 207.42g)	$4,481,416,118	

PRODUCTION O & M - FCR = $\frac{A-B-C+D-E}{F}$ 0.058

TRANSMISSION

A. Total Transmission Expenses (p. 321.100b)	$10,915,790
B. Transmission By Others (p. 321.88b)	$573,848
C. Total Transmission Plant Investment (p. 207.53g)	$411,307,026

TRANSMISSION O & M - FCR $\frac{A-B}{C}$ 0.025

OTHER TAXES EXPENSE

X. Other Taxes (Electric Only) (p. 115.13e less {p. 263.25i,.26i,.27i,.28i,.41i and 263A.53i,.54i, & .55i})	$109,408,78[illegible]
Y. Electric Plant in Service (p. 207.88g)	$7,582,668,954

OTHER TAXES - FCR $\frac{X}{Y}$ 0.014

A & G EXPENSE

A. Production Wages Expense (p. 354.18b)	$127,266,853
B. Transmission Wages Expense (p. 354.19b)	$4,154,814
C. A & G Wages Expense (p. 354.24b)	$35,881,896
D. Total Wages Expense (p. 354.25b)	$243,885,471
E. Total A & G Related O & M (p. 323.168b)	$186,025,825
P. Total Production Plant Investment (p. 207.42g)	$4,481,416,118
T. Total Transmission Plant Investment (p. 207.53g)	$411,307,026

PRODUCTION A & G - FCR = A/(D-C) * E/P 0.0254

TRANSMISSION A & G - FCR = B/(D-C) * E/T 0.0090

DEPRECIATION EXPENSE

DEp = Production Depreciation Expense (Sum of p. 336.2b-336.6b less Total Nuclear Decommissioning Expense)	$118,004,548
DEt = Transmission Depreciation Expense (p. 336.7b)	$6,959,222
DEg = General Plant Depreciation Expense(p 336.9b)	$8,741,654
P = Total Production Plant Investment (p. 207.42g)	$4,481,416,118
T = Total Transmission Plant Investment (p. 207.53g)	$411,307,026
G = Total General Plant Investment (p. 207.83g)	$413,924,993

Production Depreciation

$$SLDp = \frac{DEp}{P}$$ 2.63%

$$n(\text{depreciable years}) = \frac{1}{SLDp}$$ 38.0

PRODUCTION DEPRECIATION - FCR =

$$SFDp = \frac{ROR}{(1+ROR)^{n} - 1}$$ 0.0029

Transmission Depreciation

$SLDt = \dfrac{DEt}{T}$ 1.69%

n(depreciable years) = $\dfrac{1}{SLDt}$ 59.1

TRANSMISSION DEPRECIATION - FCR =

$SFDt = \dfrac{ROR}{(1+ROR)^{n} - 1}$ 0.0004

General Plant Depreciation

$SLDg = \dfrac{DEg}{G}$ 2.11%

n(depreciable years) = $\dfrac{1}{SLDg}$ 47.4

GENERAL PLANT DEPRECIATION - FCR =

$SFDg = \dfrac{ROR}{(1+ROR)^{n} - 1}$ 0.0012

Where:

RATE OF RETURN

Component @ year end for historical period

Component @ 12/31/94	Ratio A	Cost Rate B	Weighted Cost A * B	
Long Term Debt	41.26%	7.15%	2.95%	
Preferred Stock	5.17%	6.14%	0.32%	
Common Stock	53.57%	12.26%	6.57%	
Totals:	100.00%		ROR = Sum of Weighted Cost	9.84%

RATE OF RETURN ADJUSTED TO GROSS PLANT

PRODUCTION

A. Total Production Plant Investment (p. 207.42g)	$4,481,416,118
B. Accum. Prov. for Depr. (p. 219.18c - 22c)	$1,500,575,170
C. Net Production Plant (A-B)	$2,980,840,948

PRODUCTION ROR(A) = $\dfrac{C}{A} * ROR$ 0.0654

TRANSMISSION

A. Total Transmission Plant Investment (p. 207.53g) $411,307,026

B. Accum. Prov. for Depr. (p.219.23c) $150,436,600

C. Net Transmission Plant (A-B) $260,870,426

TRANSMISSION ROR(A) = $\frac{C}{A}$ * ROR 0.062

GENERAL

A. Total General Plant Investment (p. 207.83g) $413,924,993
LESS

B. Accum. Prov. for Depr. (p.219.25c) $85,780,582

C. Net General Plant (A-B) $328,144,411

GENERAL ROR(A) = $\frac{C}{A}$ * ROR 0.078

COMPOSITE INCOME TAX EXPENSE

CIT - FCR = (.385)/(1-.385)*(ROR(A)+SFD-SLD)*(1-Wtd. Long Term Debt/ROR(A))

Production C. I. T. - FCR	>	0.014
Transmission C. I. T. - FCR	> (as per formula)	0.0151
General Plant C. I. T. - FCR	>	0.022

GENERAL PLANT

A.	Production Wages Expense (p. 354.18b))	$127,266,853
B.	Transmission Wages Expense (p. 354.19b)	$4,154,814
C.	A & G Wages Expense (p. 354.24b)	$35,881,895
D.	Total Wages Expense (p. 354.25b)	$243,885,471
E.	Total General Plant Investment (p. 207.83g)	$413,924,993
P.	Total Production Plant Investment (p. 207.42g)	$4,481,416,118
T.	Total Transmission Plant Investment (p. 207.53g)	$411,307,026

PRODUCTION PLANT GENERAL PLANT FACTOR

G.	A/(D-C)	0.6118
H.	General Plant (DEPR + CIT+ Other Taxes + ROR(A))	0.1162
I.	Total General Plant Investment (p. 207.83g)	$413,924,993
J.	General Plant Revenue Requirement (H.* I.)	$48,081,361
K.	Production Related General Plant (G.* J.)	$29,418,550

PRODUCTION GENERAL PLANT FACTOR - FCR = K/P 0.0066

TRANSMISSION PLANT GENERAL PLANT FACTOR

V.	B/(D-C)	0.0200
J.	General Plant Revenue Requirement (H.*I.)	$48,081,361
M.	Transmission Related General Plant(V. * J.)	$960,412

TRANSMISSION GENERAL PLANT FACTOR - FCR = M/T 0.0023

CASH WORKING CAPITAL

A.	Total Production Expense (p. 321[illegible])	$718,594,440
B.	Total Transmission Expense (p. 3[illegible]00b)	$10,915,790
C.	Total Electric O & M Expenses (p. 323.169b)	$1,053,228,214
D.	Total Prepayments (p. 110.46d)	$11,758,128
P.	Total Production Plant Investment (p. 207.42g)	$4,481,416,118
T.	Total Transmission Plant Investment (p. 207.53g)	$411,307,026

PRODUCTION PLANT CASH WORKING CAPITAL - FCR =

$$\frac{A*D}{C*P} \quad (ROR-((Wtd.LTD)*.385))/(1-.385) \qquad 0.0003$$

TRANSMISSION PLANT CASH WORKING CAPITAL - FCR =

$$\frac{B*D}{C*T} \quad (ROR-((Wtd.LTD)*.385))/(1-.385) \qquad 0.00004$$

MATERIALS AND SUPPLIES

PRODUCTION

A.	Fuel Stock (p. 227.1b & 1c [avg.])	$44,087,213
B.	Materials & Supplies (p. 227.7b & .7c [avg.])	$39,371,387
C.	Total Production Plant Investment (p. 207.42g)	$4,481,416,118

Production Materials & Supplies - FCR =

$$\frac{(A+B)}{C} \quad (ROR-((Wtd.LTD)*.385))/(1-.385) \qquad 0.0026$$

TRANSMISSION

A.	Materials & Supplies (p227.8b & 8c [avg.])	$362,212
B.	Total Transmission Plant Investment (p.207.53g)	$411,307,026

Transmission Materials & Supplies - FCR =

$$\frac{A}{B} \quad (ROR-((Wtd.LTD)*.385))/(1-.385) \qquad 0.0001$$

Accumulated Deferred Income Taxes

A.	Electric Plant in Service(p. 207.88g)	$7,582,668,954
B.	Account 190(p. 234.8c)	$154,393,000
C.	Account 282(p. 275.2k)	$1,503,967,362

D. COSS Factor = Ratio of ADIT remaining after deductions for certain ADIT that is deducted from Rate Base and treated as non-operating income divided by (C - B) — 0.6350

E. Production Factor = Proportion of ADIT related to Production — 0.7600

Production [ADIT] =

$$\frac{B-C}{A} * D * E \qquad -0.0859$$

F. Transmission Factor = Proportion of ADIT related to Transmission — 0.02

Transmission [ADIT]

$$\frac{B-C}{A} * D * F \qquad -0.0023$$

FIXED CHARGE RATE CALCULATION

		PRODUCTION	TRANSMISSION
(1) Operation & Maintenance Expense	>	0.0581	0.0251
(2) Other Taxes	>	0.0144	0.0144
(3) Administrative & General Expense	>	0.0254	0.0090
(4) Return - ROR(A)	>	0.0654	0.0624
(5) SFD Depreciation	> (as calculated per previous pages)	0.0029	0.0004
(6) Composite Income Tax	>	0.0144	0.0151
(7) General Plant	>	0.0066	0.0023
(8) Cash Working Capital	>	0.0003	0.0000
(9) Material and Supplies	>	0.0026	0.0001
(10) [ADIT] *((4) + (6) above)	>	-0.0069	-0.0002
FIXED CHARGE RATE	(Sum of (1) through (10))	0.1832	0.1288

PRODUCTION

A. INVESTMENT TOTAL PRODUCTION PLANT (p. 207.42g) $4,481,416,118

B. ANNUAL REVENUE REQUIREMENT = FCR * A $821,060,649

C. DEMAND UNITS (in kW)=((Average of p.401.29(d) through 40(d) 5,471,574
less (.5 * the average of the monthly UE system coincident interruptible demands))

PRODUCTION DEMAND RATE (per kW - year) = $\frac{B}{C}$ $150.06

TRANSMISSION

A. INVESTMENT TOTAL TRANSMISSION PLANT (p. 207.53g) $411,307,026

B. ANNUAL REVENUE REQUIREMENT = FCR * A $52,992,623

C. TRANSMISSION DEMAND LOSS FACTOR = (1 - TRANSMISSION DEMAND LOSS FACTOR [.0194])

D. ADJUSTED ANNUAL REVENUE REQUIREMENT = B / C $54,041,018

E. DEMAND UNITS (in kW)=((Average of p.401.29(d) through 40(d) 5,471,574
less (.5 * the average of the monthly UE system coincident interruptible demands)

TRANSMISSION DEMAND RATE (per kW - year) = $\frac{D}{E}$ $9.88

CALCULATION OF SEASONAL PRODUCTION AND TRANSMISSION DEMAND RATES

A. ANNUAL PRODUCTION AND TRANSMISSION DEMAND RATE : Sum of Demand Rates calculated above

B. SEASONAL RATES:

WINTER RATE (January through May and October through December)=WR
SUMMER RATE (June through September) = 1.7 * WR

C. SEASONAL RATE CALCULATION (Demand data from Appendix 1)

WR * (Sum of the Firm Winter Demands + .5 * Sum of the Interruptible Winter Demands)
+ 1.7 * WR * (Sum of the Firm Summer Demands + 0.5 * Sum of the Interruptible Summer Demands)
= A * (Average of the Firm Demands + .5 * Average of the Interruptible Demands)

WINTER RATE (per kW - month) =	$10.51	as calculated above
SUMMER RATE (per kW - month) =	$17.87	as calculated above

ILLINOIS NUCLEAR DECOMMISSIONING EXPENSE

(Initially set at $ 425,000. Thereafter, to be updated every third year consistent with the following formula, beginning in the year 2000)

A. ANNUAL REVENUE REQUIREMENT: $425,000
(based on study defining the amount necessary for appropriate funding)

B. DEMAND UNITS (in kW) =(Sum of the Firm Demands 5,330,000
+ .5 * the Sum of the Interruptible Demands from Appendix 1)

NUCLEAR DECOMMISSIONING CHARGE = $\frac{A}{B}$ $0.08
(per kW - month)

(To be added to each monthly Demand Rate as calculated above)

CALCULATION OF THE MONTHLY FORMULA DEMAND RATE

The monthly formula demand rate is the sum of the appropriate Seasonal Demand Rate plus the Nuclear Decommissioning Charge. The monthly demand charge is the sum of the monthly formula demand rate times the Firm Demand plus .5 times the monthly formula demand rate times the Interruptible Demand. (All demand data from Appendix 1.)

APPENDIX 4
FORMULA RATE
FOR ENERGY RELATED CHARGES
(PAGE CITES REFER TO FERC FORM 1 DATA)

Energy-Related O & M

Steam Power

Fuel (P. 320.5b)	$286,188,076
Steam Expenses (P. 320.6b)	$9,123,511
Maintenance Supervision & Engineering (P. 320.15b).	$6,958,786
Maintenance of Boiler Plant (P. 320.17b)	$52,207,154
Maintenance of Electric Plant (P. 320.18b)	$19,362,782

Nuclear

Fuel (P. 320.25b)	$52,351,999
Maintenance Supervision & Engineering (P. 320.35b)	$3,990,021
Maintenance of Reactor Plant Equipment (P. 320.37b)	$7,123,022
Maintenance of Electric Plant (P.320.38b)	$4,223,108

Hydraulic

Maintenance of Electric Plant (P. 321.56b)	$722,347

Other

Fuel (P. 321.63b)	$1,293,755
TOTAL (A)	$443,544,561

Purchase Power Energy Expense (B) (P. 327B.14k)	$125,238,545
Sales For Resale Energy Revenue (C) (P. 311C.12i)	$139,134,079

Sales (MWh)

Ultimate Consumer (P. 401.22b)	30,351,915
Sales for Resale (P. 401.23b)	1,623,374
Total Sales (D)	31,975,289

Energy Rate (in $ per MWh) $\frac{A + B - C}{D} =$ $13.44

COST OF CAPITAL SUMMARY

31-Dec-94

Type of Capital	$Amount	Proportion of Total	Cost of Each Type	Cost
Long Term Debt (Incl NF Lease)	1,749,398,834	41.26%	7.153%	2.950%
Preferred Stock	219,173,100	5.17%	6.141%	0.320%
Common Stock	2,271,318,764	53.57%		
TOTAL	4,239,890,698	100.00%		

Name of Respondent	This Report Is:	ate of Report	Year of Report
Union Electric Company	(1) X An Original (2) __ A Resubmission	c,Da,Yr)	Dec. 31,1994

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
53	DEFERRED DEBITS			
54	Unamortized Debt Expenses (181)		$11,883,857	$12,047,325
55	Extraordinary Property Losses (182.1)	230	0	0
56	Unrecovered Plant and Regulatory Study Costs (182.2)	230	1,028,890	0
57	Other Regulatory Assets (182.3)	232	785,259,250	754,637,529
58	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
59	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)		0	0
60	Clearing Accounts (184)		1,967,287	2,119,418
61	Temporary Facilities (185)		70,670	65,140
62	Miscellaneous Deferred Debits (186)	233	4,256,677	2,306,298
63	Def. Losses from Disposition of Utility Plt. (187)		0	0
64	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
65	Unamortized Loss on Reacquired Debt (189)		41,566,765	37,284,897
66	Accumulated Deferred Income Taxes (190)	234	147,974,000	156,256,000
67	Unrecovered Purchased Gas Costs (191)		0	0
68	TOTAL Deferred Debits (Enter Total of lines 54 thru 67)		994,017,596	964,817,208
69	TOTAL Assets and Other Debits (Enter Total of Lines 10, 11, 12, 22, 52, and 68)		$6,743,544,284	$6,780,957,494

Union Electric Company	This Report Is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo,Da,Yr)	Year of Report Dec. 31, 1994

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)	
1	PROPRIETARY CAPITAL				
2	Common Stock Issued (201)	250-251	$510,834,120	$510,834,120	
3	Preferred Stock Issued (204)	250-251	219,199,100	219,173,100	
4	Capital Stock Subscribed (202, 205)	252	0	0	
5	Stock Liability for Conversion (203, 206)	252	0	0	
6	Premium on Capital Stock (207)	252	712,546,956	712,546,956	
7	Other Paid-In Capital (208-211)	253	5,122,017	5,122,017	
8	Installments Received on Capital Stock (212)	252	0	0	
9	(Less) Discount on Capital Stock (213)	254	0	0	
10	(Less) Capital Stock Expense (214)	254	0	0	
11	Retained Earnings (215, 215.1, 216)	118-119	980,021,643	1,046,546,621	
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	(2,141,306)	(5,780,561)	
13	(Less) Reacquired Capital Stock (217)	250-251	214,950	214,950	
14	TOTAL Proprietary Capital (Enter Total of lines 2 thru 13)		2,425,367,580	2,485,227,303	
15	LONG-TERM DEBT				
16	Bonds (221)	256-257	✓ 1,307,000,000	1,407,000,000	
17	(Less) Reacquired Bonds (222)	256-257	0	0	
18	Advances from Associated Companies (223)	256-257	0	0	
19	Other Long-Term Debt (224)	256-257	✓ 401,585,000	376,585,000	
20	Unamortized Premium on Long-Term Debt (225)		75,834	45,162	} 10, 134, 26
21	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		10,574,047	10,179,426	
22	TOTAL Long-Term Debt (Enter Total of lines 16 thru 21)		1,698,086,787	1,773,450,736	
23	OTHER NONCURRENT LIABILITIES				
24	Obligations Under Capital Leases - Noncurrent (227)		✓ 68,567,710	88,037,951	See Calculation on Cost of Money Sheet
25	Accumulated Provision for Property Insurance (228.1)		0	0	
26	Accumulated Provision for Injuries and Damages (228.2)		8,448,223	13,068,184	
27	Accumulated Provision for Pensions and Benefits (228.3)		0	0	
28	Accumulated Miscellaneous Operating Provisions (228.4)		21,883,000	19,108,668	
29	Accumulated Provision for Rate Refunds (229)		0	0	
30	TOTAL Other Noncurrent Liabilities (Enter Total of lines 24 thru 29)		98,898,933	120,214,803	
31	CURRENT AND ACCRUED LIABILITIES				
32	Notes Payable (231)		✓ 59,600,000	0	
33	Accounts Payable (232)		168,400,353	74,104,535	
34	Notes Payable to Associated Companies (233)		0	0	
35	Accounts Payable to Associated Companies (234)		0	0	
36	Customer Deposits (235)		12,092,356	12,241,499	
37	Taxes Accrued (236)	262-263	42,724,535	53,434,862	
38	Interest Accrued (237)		41,252,323	55,909,213	
39	Dividends Declared (238)		3,301,438	3,301,028	
40	Matured Long-Term Debt (239)		0	0	
41	Matured Interest (240)		0	0	
42	Tax Collections Payable (241)		4,054,930	4,213,389	
43	Miscellaneous Current and Accrued Liabilities (242)		110,180,163	54,551,192	
44	Obligations Under Capital Leases-Current (243)		✓ 30,539,250	30,317,522	See Calculation on Cost of Money Sheet
45	TOTAL Current and Accrued Liabilities (Enter Total of lines 32 thru 44)		$472,145,368	$288,073,340	

CALCULATION OF HISTORICAL CAPITAL STRUCTURE

31-Dec-94

Calculation of Amount of Long Term Debt (F&S Page A13)

Non-Current Long Term Debt	$1,833,622,951	
Plus: Current Maturities	68,317,622	
Less: Non-Current Nuclear Lease Capitalized	88,037,951	
Less: Current Nuclear Lease Capitalized	30,317,622	
Plus: Unamortized Nuclear Fuel in Core	30,196,372	
Long Term Debt	$1,813,781,372	
Less: Face Amount of Issue Less Withdrawls; ($44,000,000 5.45% 2028 Issue)	4,816,051	
Total Long Term Debt	1,808,965,321	
Less: Unamortized Premium and Discount	(10,134,264)	
Less: Unamortized Debt Issuance Expense	(12,047,326)	
Less: Unamortized Losses on Reacquired Debt	(37,384,897)	
TOTAL LONG TERM DEBT OUTSTANDING	$1,749,398,834	41.26%

Calculation of Amount of Preferred Stock

Preferred Stock Not Subject to Mandatory Redemption	$218,497,100	
Preferred Stock Subject to Mandatory Redemption	$676,000	
TOTAL PREFERRED STOCK	$219,173,100	5.17%

Calculation of Amount of Common Equity

Consolidated Common Equity	$2,269,054,203	
Less: Unappropriated undistributed Subsidiary Earnings	($5,780,561)	
Less: Acquisition Cost of Subsidiaries	$3,516,000	
TOTAL COMMON EQUITY	$2,271,318,764	53.57%

TOTAL CAPITALIZATION	$4,239,890,698	100.00%

UNION ELECTRIC COMPANY
COST OF LONG TERM DEBT

AS OF
31-Dec-94

DESCRIPTION OF ISSUE				31-Dec-94	ANNUALIZED	
COUPON RATE	MATURITY DATE	DATE ISSUED	PRINCIPAL ISSUED	OUTSTANDING PRINCIPAL	COST TO COMPANY	EMBEDDED COST
FIRST MORTGAGE BONDS						
4.500%	01-Apr-95	01-Apr-65	$35,000,000	$35,000,000	$1,575,000	
4.750%	01-Jun-95	01-Jun-65	3,000,000	3,000,000	142,500	
5.625%	01-Mar-96	01-Mar-66	5,000,000	5,000,000	281,250	
5.500%	01-May-96	01-May-66	30,000,000	30,000,000	1,650,000	
5.500%	01-Mar-97	01-Mar-67	40,000,000	40,000,000	2,200,000	
5.625%	01-Apr-97	01-Apr-67	5,000,000	5,000,000	281,250	
6.750%	15-Oct-99	15-Oct-92	100,000,000	100,000,000	6,750,000	
8.330%	16-Dec-2002	16-Dec-91	75,000,000	75,000,000	6,247,500	
7.650%	15-Jul-2003	01-Jan-92	100,000,000	100,000,000	7,650,000	
6.875%	01-Aug-2004	01-Feb-93	188,000,000	188,000,000	12,925,000	
7.375%	15-Dec-2004	15-Dec-92	85,000,000	85,000,000	6,268,750	
6.750%	01-May-2008	07-May-93	148,000,000	148,000,000	9,990,000	
7.400%	01-May-2020	01-May-90	60,000,000	60,000,000	4,440,000	
8.750%	01-Dec-2021	01-Dec-91	125,000,000	125,000,000	10,937,500	
8.250%	15-Oct-2022	15-Oct-92	104,000,000	104,000,000	8,580,000	
8.000%	15-Dec-2022	15-Dec-92	85,000,000	85,000,000	6,800,000	
7.150%	01-Aug-2023	01-Aug-93	75,000,000	75,000,000	5,362,500	
7.000%	15-Jan-2024	15-Jan-94	100,000,000	100,000,000	7,000,000	
5.450%	01-Oct-2028	15-Oct-93	44,000,000	39,183,949	2,135,525	
POLLUTION CONTROL BONDS						
4.248%	01-Jun-2014	01-Jun-84	$160,000,000	$160,000,000	$6,797,125	
4.382%	01-Jun-2015	01-Jun-85	126,500,000	126,500,000	5,543,368	
4.200%	01-Dec-2020	01-Dec-91	42,585,000	42,585,000	1,788,570	
5.180%	01-Dec-2022	01-Dec-92	47,500,000	47,500,000	2,460,500	
COMPETITIVE ADVANCE & REVOLVING CREDIT FACILITY						
VARIABLE	08-Nov-95		0	0	0	
COMMERCIAL PAPER BACKUP/REVOLVING CREDIT AGREEMENT						
VARIABLE	15-Aug-96	01-Aug-89	0	0	0	
NUCLEAR FUEL LEASE						
6.007%	24-Feb-2031		30,196,372	30,196,372	1,813,898	
LESS: UNAMORTIZED PREMIUM & DEBT DISCOUNT:				(10,134,264)		
LESS: UNAMORTIZED DEBT ISSUANCE EXPENSE:				(12,047,326)		
LESS: UNAMORTIZED LOSSES ON REACQUIRED DEBT:				(37,384,897)		
ADD: ANNUAL AMORTIZED DEBT DISCOUNT EXPENSE:					553,764	
ADD: ANNUAL AMORTIZED DEBT ISSUANCE EXPENSE:					770,976	
ADD: ANNUAL AMORTIZED LOSSES ON REACQUIRED DEBT EXPENSE:					4,181,868	
TOTAL:	(All Long Term Debt, Including Nuclear Fuel Lease)			$1,749,398,834	$125,126,844	7.153%
TOTAL:	(All Long Term Debt, Excluding Nuclear Fuel Lease)			$1,719,202,462	$123,312,946	7.173%

1,402,183,949

376,585,000

Functionalization of Accumulated Deferred Income Taxes

Deferred Taxes	Total	Electric	Production	Ratio
190	49	48	24	0.5
282	(915)	(902)	(677)	0.75
		(854)	(653)	0.76

	Electric	Production	Transmission
282 Only	798	599	10.2
		34	0.5
	3	3	0.2
	44	28	0.5
	6		1.5
	7		1.6
	30		1.5
	888	664	16
	Ratio	0.75	0.02

COSS Factor	Electric	Total Electric	Ratio
190	48	154.4 (B)	
282	(905)	1504(C)	
	(857)(A)	A/(C-B)=	0.635

UNION ELECTRIC COMPANY PAGE [illegible]
ALLOCATION OF ACCUM. DE[illegible]D INCOME TAXES
12 MONTHS ENDED 12/31/94

ACCOUNT 190:	ALLOCATION:	TOTAL	ULTIMATE CONSUMERS MISSOURI	ULTIMATE CONSUMERS ILLINOIS	SALES FOR RESALE
POST 1977 VAC. PAY ACC.	(LABOR)	(7,749,000)	(6,847,791)	(650,916)	(250,293)
POST 1977 EXCESS RES. PREM.	(FIXED)	(1,145,000)	(1,003,592)	(86,219)	(55,189)
POST 1977 INT. ENVIR. BONDS	(FIXED)	(3,428,000)	(3,004,642)	(258,128)	(165,230)
POST 1977 DISCOUNT - W/H CR.	(FIXED)	(1,663,000)	(1,457,619)	(125,224)	(80,157)
POST 1977 DEF. COMPENSATION	(FIXED)	(10,435,000)	(9,146,783)	(785,057)	(503,160)
POST 1977 SNUPPS DESIGN SALE	(FIXED)	(123,000)	(107,809)	(9,262)	(5,929)
POST 1977 PENSION EXPENSE	(LABOR)	(294,000)	(259,808)	(24,696)	(9,496)
POST 1977 FASB 106 LIABILTY	(LABOR)	(21,649,000)	(19,307,961)	(1,835,316)	(705,723)
POST 1977 SALE OF EMIS. CR.	(VARIABLE)	(382,000)	(320,307)	(43,090)	(18,603)
POST 1977 ENVIRON. CLEAN-UP	(NET PLANT)	(1,070,000)	(961,074)	(70,406)	(38,520)
TOTAL ACCOUNT 190		(48,140,000)	(42,420,386)	(3,889,314)	(1,832,300)
ACCOUNT 282:					
ACCOUNT 282-11:					
ILLINOIS-STATE & FEDERAL	(DIRECT)	4,170,536	0	4,170,536	0
FEDERAL:					
PRODUCTION 1975-77 (1)	(FIXED)	42,958,800	37,653,398	3,234,792	2,070,614
POST 1977	(FIXED)	553,415,100	485,068,335	41,672,157	26,674,608
TRANSMISSION 1975-77 (1)	(FIXED)	5,106,900	4,476,197	384,550	246,153
POST 1977	(FIXED)	4,680,600	4,102,546	352,449	225,605
DISTRIBUTION 1975-77 (1)	(DISTRIBUTION)	14,382,600	13,515,329	759,401	107,870
POST 1977	(DISTRIBUTION)	105,520,600	99,157,707	5,571,488	791,405
GENERAL 1975-77 (1)	(LABOR)	520,700	461,910	43,907	16,883
POST 1977	(LABOR)	24,710,900	21,837,022	2,075,716	798,162
TOTAL FEDERAL		751,298,200	666,272,434	54,094,466	30,931,300
STATE:					
PRODUCTION 1975-77 (1)	(FIXED)	1,494,800	1,310,193	112,559	72,048
POST 1977	(FIXED)	32,654,500	28,621,659	2,458,894	1,573,947
TRANSMISSION 1975-77 (1)	(FIXED)	177,700	155,754	13,381	8,565
POST 1977	(FIXED)	276,200	242,089	20,798	13,313
DISTRIBUTION 1975-77 (1)	(DISTRIBUTION)	500,400	470,226	26,421	3,753
POST 1977	(DISTRIBUTION)	6,226,300	5,850,854	328,749	46,697
GENERAL 1975-77 (1)	(LABOR)	18,200	16,083	1,529	588
POST 1977	(LABOR)	1,458,100	1,288,523	122,480	47,097
TOTAL STATE		42,806,200	37,955,381	3,084,800	1,766,009
TOTAL ACCT. 282-11		$798,274,936	$704,227,825	$61,349,802	$32,697,309

(1) F.E.R.C. RATES DID NOT INCLUDE NORMALIZATION UNTIL 1976. THEREFORE, THESE AMOUNTS WERE NOT COLLECTED FROM THE F.E.R.C. OR ANY JURISDICTION.

			ULTIMATE CONSUMERS		SALES FOR
ACCOUNT 282 (CONTINUED):					
ACCOUNT 282-13:	ALLOCATION:	TOTAL	MISSOURI	ILLINOIS	RESALE
TRANSMISSION PRE-1978 (1)	(FIXED)	$1,461,000	$1,280,567	$110,013	$70,420
1978-80	(FIXED)	1,630,000	1,428,695	122,739	78,566
POST 1980	(FIXED)	1,453,000	1,273,554	109,411	70,035
TOTAL TRANSMISSION		4,544,000	3,982,816	342,163	219,021
DISTRIBUTION PRE-1978 (1)	(DISTRIBUTION)	4,100,000	3,852,770	216,480	30,750
1978-80	(DISTRIBUTION)	5,420,000	5,093,174	286,176	40,650
POST 1980	(DISTRIBUTION)	28,951,000	27,205,254	1,528,613	217,133
TOTAL DISTRIBUTION		38,471,000	36,151,198	2,031,269	288,533
TOTAL ACCT. 282-13		43,015,000	40,134,014	2,373,432	507,554
ACCOUNT 282 (EXCL. 11 & 13) (2):					
RAPID AMORTIZATION	(DIRECT)	8,042,000	0	0	8,042,000
UNFUNDED TAX LIABILITY	(DIRECT)	787,000	0	0	787,000
WESTERN NUCLEAR	(VARIABLE)	7,833,000	6,567,971	923,562	381,457
CALLAWAY TRAINING	(FIXED)	222,000	194,583	16,717	10,700
PRODUCTION PRE-1978 (1)	(FIXED)	2,513,000	2,202,644	189,229	121,127
POST 1977	(FIXED)	27,503,000	24,106,379	2,070,976	1,325,645
TRANSMISSION PRE-1978 (1)	(FIXED)	196,000	171,794	14,759	9,447
POST 1977	(FIXED)	494,000	432,991	37,198	23,811
DISTRIBUTION PRE-1978 (1)	(DISTRIBUTION)	498,000	467,971	26,294	3,735
POST 1977	(DISTRIBUTION)	11,135,000	10,463,559	587,928	83,513
GENERAL PRE-1978 (1)	(LABOR)	72,000	63,626	6,048	2,326
POST 1977	(LABOR)	4,586,000	4,052,648	385,224	148,128
TOTAL A/C 282 (EXCLUDING 11 & 13)		63,881,000	48,724,166	4,217,935	10,938,899
TOTAL ACCOUNT 282		905,170,936	793,086,005	67,941,169	44,143,762
ELIMINATION OF F.E.R.C. PRE-1978 AMTS. (1)		(2,764,280)	0	0	(2,764,280)
ADJUSTED ACCOUNT 282		$902,406,656	$793,086,005	$67,941,169	$41,379,482

(1) F.E.R.C. RATES DID NOT INCLUDE NORMALIZATION UNTIL 1978. THEREFORE, THESE AMOUNTS WERE NOT COLLECTED FROM THE F.E.R.C. OR ANY JURISDICTION.
(2) EXCLUDES THOSE AMOUNTS RELATED TO CALLAWAY DISALLOWANCES.

481,40,00

UNION ELECTRIC COMPANY
FUNCTIONALIZATION OF ACCUMULATED DEFERRED INCOME TAXES
12 MONTHS ENDED 12/31/84

ACCT 282 - DEPRECIATION:	PRE-1975	1975-1977	POST 1977		ILLINOIS	POST 1974	
MINOR 111 FEDERAL:	%	%	%	TOTAL	PRE-1975	PRE-1978	POST 1977
PRODUCTION	70.27%	69.22%	80.40%	$599,225,200	$2,855,300	$42,959,800	$553,415,100
TRANSMISSION	10.49%	9.11%	0.68%	10,212,700	426,200	5,106,900	4,680,600
DISTRIBUTION	19.69%	22.84%	15.33%	120,705,300	800,100	14,382,600	105,520,100
GENERAL	-0.45%	0.83%	3.59%	25,215,384	(18,216)	522,700	24,710,500
TOTAL FEDERAL	100.00%	100.00%	100.00%	755,361,584	4,063,384	62,971,000	688,327,200
MINOR 112 STATE:							
PRODUCTION	70.27%	69.22%	80.40%	34,224,600	75,300	1,494,800	32,654,500
TRANSMISSION	10.49%	9.11%	0.68%	455,100	11,200	177,700	276,200
DISTRIBUTION	19.69%	22.84%	15.33%	6,747,800	21,100	500,400	6,226,300
GENERAL	-0.45%	0.83%	3.59%	1,475,552	(448)	18,200	1,458,100
TOTAL STATE	100.00%	100.00%	100.00%	42,913,352	107,152	2,191,100	40,615,100
TOTAL ACCOUNT 282 MINORS 111 & 112				$798,274,936	$4,170,536	$65,162,100	$728,942,300

UNION ELECTRIC COMPANY
FUNCTIONALIZATION OF ACCUMULATED DEFERRED INCOME TAXES
12 MONTHS ENDED 12/31/94

ACCOUNT 282 EXCL.DEPRECIATION, UNFUNDED TAX LIABILITY, CALLAWAY RELATED, & REPAIR ALLOWANCE.:	PRE-1978		POST 1977	
FUNCTIONALIZATION:	%	AMOUNT	%	AMOUNT
PRODUCTION	76.65%	$2,515,000	62.91%	$27,503,000
TRANSMISSION	5.97%	196,000	1.13%	494,000
DISTRIBUTION	15.20%	498,000	25.47%	11,135,000
GENERAL	2.19%	72,000	10.49%	4,586,000
TOTAL	100.00%	$3,275,000	100.00%	$43,719,000

ACCOUNT 282 REPAIR ALLOWANCE:	PRE-1978		1978 - 80		POST 1980	
FUNCTIONALIZATION:	%	AMOUNT	%	AMOUNT	%	AMOUNT
TRANSMISSION	26.27%	$1,461,000	23.12%	$1,630,000	4.78%	$1,453,0
DISTRIBUTION	73.73%	4,100,000	76.88%	5,420,000	95.22%	28,951,0
TOTAL	100.00%	$5,561,000	100.00%	$7,050,000	100.00%	$30,404,0

UNION ELECTRIC COMPANY
ACCUMULATED DEFERRED INCOME TAXES
12 MONTHS ENDED 12/31/94

ACCOUNT 282 - EXCLUDING DEPRECIATION:	TOTAL	PRE-1978	POST 1977	RAPID AMORT. FERC CALLAWAY (1)
MINORS 121 & 122 REMOVAL COSTS	$236,000	$34,000	$202,000	$0
MINORS 901 THRU 992 INTEREST	30,824,000	1,515,000	22,177,000	7,132,000
MINORS 151 & 152 EXPENSES	7,435,000	337,000	6,921,000	51,000
MINORS 161 & 162 PENSIONS	5,661,000	436,000	5,171,000	54,000
MINORS 171 & 172 PAYROLL TAXES	5,744,000	331,000	5,358,000	55,000
MINORS 181 & 182 PROPERTY TAXES	3,335,000	205,000	2,999,000	131,000
MINORS 191 & 192 SALES & USE TAXES	1,538,000	112,000	1,372,000	54,000
MINORS 231 & 232 CALLAWAY TRAINING	222,000	0	222,000	0
MINORS 241 & 242 UNFUNDED TAX LIABILITY	727,000	0	727,000	0
MINORS 251 & 252 WESTERN NUCLEAR	7,533,000	0	7,533,000	0
TOTAL	63,281,000	3,379,000	52,560,000	7,342,000
		PRE-1979	1979-80	POST 1980
MINORS 131 & 132 REPAIR ALLOWANCE	43,615,000	5,561,000	7,650,000	30,404,000
TOTAL ACCOUNT 282 EXCLUDING DEPRECIATION	106,896,000			
TOTAL ACCOUNT 282 (EXCLUDING DISALLOWANCES)	905,170,536			

ACCOUNT 190:		PRE-1978	POST 1977
MINORS 301 & 302 VACATION PAY ADJ.	(7,749,000)	0	(7,749,000)
MINORS 311 & 312 EXCESS RESERVE PREMIUM	(1,145,000)	0	(1,145,000)
MINORS 321 & 322 INT. INC. ON ENVIRON. BOND	(3,428,000)	0	(3,428,000)
MINORS 331 & 332 DISCOUNT - W/H CREDITS	(1,663,000)	0	(1,663,000)
MINORS 341 & 342 DEFERRED COMPENSATION	(10,439,000)	0	(10,439,000)
MINORS 351 & 352 SALE OF SNUPPS DESIGN	(123,000)	0	(123,000)
MINORS 411 & 412 PENSION EXPENSE	(294,000)	0	(294,000)
MINORS 761 & 762 FASB 106 LIABILITY	(21,849,000)	0	(21,849,000)
MINORS 771 & 772 SALE OF EMMISSION CREDITS	(382,000)	0	(382,000)
MINORS 791 & 792 ENVIRONMENTAL CLEAN-UP	(1,070,000)	0	(1,070,000)
TOTAL ACCOUNT 190	($48,142,000)	$0	($48,142,000)

(1) REFLECTS CORRECTED BALANCE FOR 33.5 YEAR AMORTIZATION VS. THREE (3) YEAR AMORTIZATION.

02/16/95

MONTHLY DEMAND AND ENERGY % LOSS MULTIPLIERS

	TRANSMISSION		H.V. DIST		DIST. PRIMARY		DIST. SECONDARY	
MONTH	DEMAND	ENERGY	DEMAND	ENERGY	DEMAND	ENERGY	DEMAND	ENERGY
JAN.	1.93%	2.13%	1.47%	1.72%	2.86%	2.40%	3.55%	3.27%
FEB.	1.94	2.16	1.45	1.55	2.59	2.09	3.57	3.19
MAR.	2.01	2.18	1.29	1.49	2.25	2.00	3.73	3.43
APR.	2.04	2.20	1.23	1.45	2.19	1.96	3.84	3.83
MAY	1.97	2.19	1.37	1.49	2.41	2.03	3.53	3.89
JUN.	1.90	2.16	1.62	1.54	2.92	2.14	3.81	3.85
JUL.	1.89	2.12	1.69	1.80	3.04	2.56	3.56	3.32
AUG.	1.89	2.14	1.71	1.68	3.08	2.32	3.71	3.20
SEPT.	1.88	2.15	1.74	1.58	3.21	2.17	3.74	3.38
OCT.	2.03	2.19	1.24	1.48	2.13	2.01	3.70	3.74
NOV.	1.98	2.18	1.34	1.51	2.36	2.08	3.56	3.80
DEC.	1.94	2.13	1.47	1.70	2.63	2.39	3.47	3.33

ANNUAL DEMAND AND ENERGY % LOSS MULTIPLIERS

TRANSMISSION		H.V. DIST		DIST. PRIMARY		DIST. SECONDARY	
DEMAND	ENERGY	DEMAND	ENERGY	DEMAND	ENERGY	DEMAND	ENERGY
1.94%	2.16%	1.50%	1.58%	2.68%	2.17%	3.66%	3.46%

APPENDIX 1

CONTRACT CAPACITY AND ENERGY

	Contract Firm Capacity (MW)	Contract Interruptible Capacity (MW)	Contract Energy (Millions of kWh)
January	400	85	300
February	400	85	300
March	350	85	300
April	350	85	280
May	350	85	280
June	450	70	320
July	500	70	320
August	500	70	320
September	450	70	320
October	350	85	280
November	350	85	280
December	400	85	300

APPENDIX 3
FORMULA RATE
FOR DEMAND RELATED CHARGES
(PAGE CITES REFER TO FERC FORM 1 DATA)

PRODUCTION

A. Total Power Production Expense (p. 321.80b)
B. Purchased Power Energy Expense (p. 327B.14k)
Energy Related O & M
Steam
    Fuel (p.320.5b)
    Steam Expenses (p.320.6b)
    Maintenance Supervision & Engineering (p.320.15b)
    Maintenance of Boiler Plant (p. 320.17b)
    Maintenance of Electric Plant (p.320.18b)
Nuclear
    Fuel (p320.25b)
    Maintenance Supervision & Engineering (p.320.35b)
    Maintenance of Reactor Plant Equipment (p. 320.37b)
    Maintenance of Electric Plant (p. 320.38b)
Hydraulic
    Maintenance of Electric Plant (p.321.56b)
Other
    Fuel (p. 321.63b)
C. Total Energy Related O & M (Sum)

D. Sales For Resale Energy Revenue (p311C.12i)
E. Sales For Resale Demand Revenue (p311C.12h)
F. Total Production Plant Investment (p. 207.42g)

PRODUCTION O & M - FCR = $\frac{A-B-C+D-E}{F}$

TRANSMISSION

A. Total Transmission Expenses (p. 321.100b)
B. Transmission By Others (p. 321.88b)
C. Total Transmission Plant Investment (p. 207.53g)

TRANSMISSION O & M - FCR = $\frac{A-B}{C}$

OTHER TAXES EXPENSE

X. Other Taxes (Electric Only) (p.115.13e less [p.263.25i,.26i,.27i,.28i,.41i and 263A.53i,.54i, & .55i])
Y. Electric Plant in Service (p. 207.88g)

OTHER TAXES - FCR = $\frac{X}{Y}$

A & G EXPENSE

A. Production Wages Expense (p.354.18b)
B. Transmission Wages Expense (p. 354.19b)
C. A & G Wages Expense (p. 354.24b)
D. Total Wages Expense (p. 354.25b)
E. Total A & G Related O & M (p. 323.168b)
P. Total Production Plant Investment (p. 207.42g)
T. Total Transmission Plant Investment (p. 207.53g)

PRODUCTION A & G - FCR = A/(D-C) * E/P

TRANSMISSION A & G - FCR = B/(D-C) * E/T

DEPRECIATION EXPENSE

DEp = Production Depreciation Expense =
(Sum of p. 336.2b-336.6b less Total Nuclear Decommissioning Expense)
DEt = Transmission Depreciation Expense (p.336.7b)
DEg - General Plant Depreciation Expense(p336.9b)
P = Total Production Plant Investment (p. 207.42g)
T = Total Transmission Plant Investment (p. 207.53g)
G - *Total General Plant Investment (p207.83g)*

Production Depreciation

SLDp = $\frac{DEp}{P}$

n(depreciable years)= $\frac{1}{SLDp}$

PRODUCTION DEPRECIATION - FCR =
SFDp = $\frac{ROR}{(1+ROR)^{n} - 1}$

Transmission Depreciation

$$SLDt = \frac{DEt}{T}$$

$$n(\text{depreciable years}) = \frac{1}{SLDt}$$

TRANSMISSION DEPRECIATION - FCR =

$$SFDt = \frac{ROR}{(1+ROR)^{n} - 1}$$

General Plant Depreciation

$$SLDg = \frac{DEg}{G}$$

$$n(\text{depreciable years}) = \frac{1}{SLDg}$$

General Plant Depreciation - FCR =

$$SFDg = \frac{ROR}{(1+ROR)^{n} - 1}$$

Where:

RATE OF RETURN
Component @ year end for historical period

	Ratio	Cost Rate	Weighted Cost
Long Term Debt	A	AR	A*AR
Preferred Stock	B	BR	B*BR
Common Stock	C	CR	C*CR
Totals:	100.00%		

ROR = Sum of Weighted Cost

RATE OF RETURN ADJUSTED TO GROSS PLANT

PRODUCTION

A. Total Production Plant Investment (p. 207.42g)

B. Accum. Prov. for Depr. (Sum of p.219.18c - 22c)

C. Net Production Plant (A-B)

PRODUCTION **ROR(A) =** $\frac{C}{A} * ROR$

TRANSMISSION
A. Total Transmission Plant Investment (p. 207.53g)

B. Accum. Prov. for Depr. (p.219.23c)

C. Net Transmission Plant (A-B)

TRANSMISSION ROR(A)= $\frac{C}{A}$ * ROR

GENERAL
A. Total General Plant Investment (p. 207.83g)

B. Accum. Prov. for Depr. (p.219.25c)

C. Net General Plant (A-B)

GENERAL ROR(A) = $\frac{C}{A}$ * ROR

COMPOSITE INCOME TAX EXPENSE

CIT - FCR = (.385)/(1-.385)*(ROR(A)+SFD-SLD)*(1-Wtd. LTD/ROR(A))

PRODUCTION CIT - FCR = >
TRANSMISSION CIT - FCR = > (as per formula)
General Plant CIT - FCR = >

GENERAL PLANT
A. Production Wages Expense (p.354.18b))
B. Transmission Wages Expense (p 354.19b)
C. A & G Wages Expense (p354.24b)
D. Total Wages Expense (p 354.25b)
E. Total General Plant Investment (p207.83g)
P. Total Production Plant Investment (p.207.42g)
T. Total Transmission Plant Investment (p 207.53g)

PRODUCTION PLANT GENERAL PLANT FACTOR

G. A/(D-C)
H. General Plant (DEPR + CIT+ Other Taxes+ROR(A))
I. Total General Plant Investment (p207.83g)
J. *General Plant Revenue Requirement (H*I)*
K. Production Related General Plant (G*J)

PRODUCTION GENERAL PLANT FACTOR - FCR = K / P

TRANSMISSION PLANT GENERAL PLANT FACTOR

V. B/(D-C)
J. General Plant Revenue Requirement (H * I)
M. Transmission Related General Plant(V * J)

TRANSMISSION GENERAL PLANT FACTOR - FCR = M / T

CASH WORKING CAPITAL

A. Total Production Expense (p 321.80b)
B. Total Transmission Expense (p 321.100b)
C. Total Electric O & M Expenses (p 323.169b)
D. Total Prepayments (p 110.46d)
P. Total Production Plant Investment (p207.42g)
T. Total Transmission Plant Investment (p 207.53g)

PRODUCTION PLANT CASH WORKING CAPITAL - FCR =

$$\frac{A*D}{C*P} *(ROR-((Wtd.LTD)*.385))/(1-.385)$$

TRANSMISSION PLANT CASH WORKING CAPITAL - FCR =

$$\frac{B*D}{C*T} *(ROR-((Wtd.LTD)*.385))/(1-.385)$$

MATERIALS AND SUPPLIES

PRODUCTION

A. Fuel Stock (p.227.1b & 1c [avg.])
B. Materials & Supplies (p227.7b &7c [avg.])
C. Total Production Plant Investment (p.207.42g)

PRODUCTION MATERIALS & SUPPLIES - FCR =

$$\frac{(A+B)}{C} *(ROR-((Wtd.LTD)*.385))/(1-.385)$$

TRANSMISSION

A. Materials & Supplies (p227.8b & 8c [avg.])
B. Total Transmission Plant Investment (p.207.53g)

TRANSMISSION MATERIALS & SUPPLIES - FCR =

$$\frac{A}{B} *(ROR-((Wtd.LTD)*.385))/(1-.385)$$

ACCUMULATED DEFERRED INCOME TAXES

A. Electric Plant in Service(p207.88g)
B. Account 190(p234.8c)
C. Account 282(p275.2k)

D. COSS Factor = Ratio of ADIT remaining after deductions for certain ADIT deducted from Rate Base and treated as non-operating income divided by (C - B)

E. Production Factor = Proportion of ADIT related to Production

PRODUCTION [ADIT] = $\frac{B-C}{A} * D * E$

F. Transmission Factor = Proportion of ADIT related to Transmission

TRANSMISSION [ADIT] = $\frac{B-C}{A} * D * F$

FIXED CHARGE RATE CALCULATION

		PRODUCTION	TRANSMISSION
(1) Operation & Maintenance Expense	>		
(2) Other Taxes	>		
(3) Administrative & General Expense	>		
(4) Return - ROR(A)	>		
(5) SFD Depreciation	>	(as calculated per previous pages)	
(6) Composite Income Tax	>		
(7) General Plant	>		
(8) Cash Working Capital	>		
(9) Material and Supplies	>		
(10) [ADIT] *((4) + (6) above)	>		
FIXED CHARGE RATE		**Sum of (1) through (10)**	

PRODUCTION

A. INVESTMENT TOTAL PRODUCTION PLANT (p. 207.42g)

B. ANNUAL REVENUE REQUIREMENT = FCR * A

C. DEMAND UNITS (in kW) =(Average of p.401.29(d) through 40(d))
less (.5 * the average of the monthly UE system coincident interruptible demands)

PRODUCTION DEMAND RATE (per kW - year) = $\frac{B}{C}$

TRANSMISSION

A. INVESTMENT TOTAL TRANSMISSION PLANT (p. 207.53g)

B. ANNUAL REVENUE REQUIREMENT = FCR * A

C. TRANSMISSION DEMAND LOSS FACTOR = (1-TRANSMISSION DEMAND LOSS MULTIPLIER)

D. ADJUSTED ANNUAL REVENUE REQUIREMENT= B / C

E. DEMAND UNITS (in kW) =(Average of p.401.29(d) through 40(d))
less (.5 * the average of the monthly UE system coincident interruptible demands)

TRANSMISSION DEMAND RATE (per kW -year) = $\frac{D}{E}$

CALCULATION OF SEASONAL PRODUCTION AND TRANSMISSION DEMAND RATES

A. ANNUAL PRODUCTION AND TRANSMISSION DEMAND RATE : Sum of Demand Rates calculated above

B. SEASONAL RATES:

WINTER RATE (January through May and October through December) = WR
SUMMER RATE (June through September) = 1.7 * WR

C. SEASONAL RATE CALCULATION (*Demand data from* Appendix 1)

WR * (Sum of the Firm Winter Demands + .5 * Sum of the Interruptible Winter Demands)
+ 1.7 * WR * (Sum of the Firm Summer Demands + .5 * Sum of the Interruptible Summer Demands)
= A * (Average of the Firm Demands + .5 * Average of the Interruptible Demands)

WINTER RATE (per kW- month) = as calculated above
SUMMER RATE (per kW- month) = 1.7 * Winter Rate

NUCLEAR DECOMMISSIONING EXPENSE

(Initally set at $425,000. Thereafter, to be updated every third year consistent with the following formula, beginning in the year 2000.)

A. ANNUAL REVENUE REQUIREMENT:
(based on study defining the amount necessary for appropriate funding)
B. DEMAND UNITS (in kW) = (Sum of the Firm Demands
+ .5 * the Sum of the Interruptible Demands from Appendix 1)

NUCLEAR DECOMMISSIONING CHARGE = $\frac{A}{B}$
(per kW - month)

(To be added to each monthly Demand Rate as calculated above)

CALCULATION OF THE MONTHLY FORMULA DEMAND RATE

The monthly *formula demand rate is the sum of the appropriate Seasonal Demand* Rate plus the Nuclear Decommissioning Charge. The monthly demand charge is the sum of the monthly formula demand rate times the Firm Demand plus .5 times the monthly formula demand rate times the Interruptible Demand. (All demand data from Appendix 1.)

CALCULATION OF ALLOCATION FACTORS

	UE		CIPS	
Electric Allocators				
Labor	71.2	%	28.8	%
KWh Sales	67.6		32.4	
Demand (12 NCP)	70.3		29.7	
Customers	73.6		26.4	
Average	70.7	%	29.3	%
Gas Allocators				
Labor	43.4	%	56.6	%
CCF Sales	26.0		74.0	
Demand	32.4		67.6	
Customers	35.2		64.8	
Average	34.3	%	64.7	%
→ Sales/Demand (Avg)	29.2	%	70.8	%
Total A&G Allocator				
to Electric	93.6	%		
to Gas	6.4			