Clinton Power Station Unit 1
Docket No. 50-461
Construction Permit No. CPPR-137

UPDATED INFORMATION FOR ANTITRUST REVIEW OF OPERATING LICENSE APPLICATION

Applicants:

Illinois Power Company (IP)

Soyland Power Cooperative, Inc. (Soyland)

Western Illinois Power Cooperative, Inc. (WIPCO)

Date: March 12, 1984

Updated Information for Antitrust Review of Operating License Application for Clinton Power Station

The information is provided per the items of Regulatory Guide 9.3.

Item No.

B.1.a - Anticipated excess or shortage in generating capacity resources not expected at the construction permit stage. Reasons for the excess or shortage along with data on how the excess will be allocated, distributed, or otherwise utilized or how the shortage will be obtained.

Responses:

IP - A copy of IP Projected Capacity and Demand at System Peak for the years 1984 through 1993, is provided herewith as Exhibit IP-1.

Soyland - None

WIPCO - See the attached table dated February 13, 1984 identified as Exhibit W-1). WIPCO plans to purchase power through its interchange agreements with Illinois Power Company and Springfield-City Water, Light and Power to cover any deficiencies.

The most recent hourly peak load on the WIPCO integrated system was 41 Mw and occurred on July 28, 1980, during the hour ending 6:00 P.M., C.D.S.T. During this same time period the thermal generating resources had a dependable capacity of 57.7 Mw. WIPCO has no hydroelectric generating capacity.

B.1.b - New power pools or coordinating groups or changes in structure, activities, policies, practices, or membership of power pools or coordinating groups in which the licensee was, is, or will be a participant.

Responses:

IP - Illinois Power Company has entered into an interconnection agreement with Kentucky-Utilities Company, dated January 1, 1983. This agreement provides for various power transactions between the parties and is designated as IP FERC Schedule No. 91. (Ill. Commerce Commission (ICC) Docket No. 83-0189.)

Early in 1982 representatives of Southern Illinois Power Cooperative (SIPC) and IP met, at SIPC's request, to review the feasibility of an interconnection between the

two systems. Studies indicated that an 138 Kv interconnection at IP's Baldwin Power Station would eliminate the need for SIPC to construct approximately sixteen miles of 69 Kv line. Although the benefits to IP are minimal, IP entered into an interconnection agreement with SIPC, dated March 3, 1983. Completion of the interconnection facilities is presently estimated by June 1, 1984. The agreement has been submitted to the REA for approval. FERC and ICC filings will follow REA approval.

Soyland - None

WIPCO - None

B.1.c - Changes in transmission with respect to (1) the nuclear plant, (2) interconnections, or (3) connections to wholesale customers.

Responses:

IP - (1) None

(2) (a) A 345 Kv interconnection was energized on October 25, 1983, between Central Illinois Public Service Company (CIPS) Kansas Substation and IP's Sidney Substation.

(b) A 138 Kv interconnection between IP and WIPCO was completed on June 25, 1982, at WIPCO's request, to serve a coal company, a customer of WIPCO near Elkhart.

(c) A 138 Kv interconnection between IP and WIPCO near Lanesville was completed on August 30, 1982. This interconnection was requested by WIPCO in order to improve service to its 69 Kv system in the area.

(d) Farmer City (See IP response to B.1.f(1)(a))

(e) Southern Illinois Power Cooperative (See IP response to B.1.b.)

(3) See IP response to B.1.f.

Soyland - (1) None
(2) None
(3) None

WIPCO - (1) None
(2) See IP response to B.1.c. (2)(b) and (c)
(3) None

B.1.d - Changes in ownership or contractual allocation of the output of the nuclear facility. Reasons and basis for such changes should be included.

Responses:

IP - No change from "Application for Amendment to Construction Permit No. CPPR - 137, Clinton Power Station, Unit 1, Docket No. 50-461" dated 1/31/78.

Soyland - None

WIPCO - None

B.1.e - Changes in design, provisions or conditions of rate schedules and reasons for such changes. Rate increases or decreases are not necessary.

Responses:

IP - (a) The agreements for Purchase of Power, under which IP's partial requirements wholesale customers are served, were amended in April, 1981 to incorporate a schedule for Supplemental Interruptible Electric Service. A copy of this schedule is attached as Exhibit IP-2.

(b) IP filed Rider S - Supplemental Interruptible Electric Service, with the ICC, effective July 3, 1981. A copy of Rider S is attached as Exhibit IP-3.

(c) On May 24, 1983, Western Illinois Power Cooperative entered into a new three year Agreement for Purchase of Power from Illinois Power Company. This Agreement will terminate upon commercial operation of Clinton Nuclear Unit #1. A copy of the Agreement is attached as Exhibit IP-4.

(d) As a part of a rate settlement reached on November 18, 1983, with the Partial Requirements Customers the Company agreed to a Short Term Energy Transmission Agreement, a copy of which is attached as Exhibit IP-5 and a long term Electric Transportation Service Agreement, a copy of which is attached as Exhibit IP-6.

(e) During 1983 the Company had discussions with the City of Peru, Illinois and made a proposal to transport energy for the city from its proposed Starved Rock Hydro Plant to its distribution facilities.

(f) Illinois Power Company modified its electric rate structure by proposing the implementation of time-of-day (TOD) energy charges applicable to large residential and industrial customers in its retail rate increase request submitted to the Illinois Commerce Commission (ICC) on August 8, 1980. The major purpose of this change was to insure that: (1) these large customers receive the proper price signals concerning their consumption decisions, and (2) the utility recover the incremental cost of supplying additional energy. These design

changes were approved by the ICC on July 1, 1981 (ICC Docket 80-0544). TOD rate implementation was expanded to large general service customers in the most recent rate increase approved by the ICC on January 12, 1983 (ICC Docket 82-0152). In addition to the TOD expansion, the Company's demand charges for residential and industrial customers are now based on the maximum monthly on-peak demand in place of a contract capacity established during the previous summer period. A copy of these two referenced ICC Orders and IP's presently effective Schedule of Rates for Electric Service (Ill. C. C. No. 27) are attached as Exhibits IP-7, IP-8 and IP-9.

Soyland - None

WIPCO - See IP response B.1.e(c).

B.1.f - List of all (1) new wholesale customers, (2) transfers from one rate schedule to another including copies of schedules not previously furnished, (3) changes in licensee's service area, and (4) licensee's acquisition or mergers.

Responses:

IP - (1) (a) An Agreement for Purchase of Power by Farmer City from IP was executed on September 26, 1983. Facilities are presently being constructed by both parties and wholesale partial requirements service is expected to commence in June, 1984.

(b) Partial requirements wholesale service was initiated for the Mt. Carmel Public Utility Co. on January 1, 1983. IP delivered power under this Purchase of Power Agreement to CIPS, who provided transmission service for Mt. Carmel.

(c) Soyland Power Cooperative, Inc. requested, and has accepted, the assignment, effective June 8, 1983, of existing wholesale power agreements between IP and the following individual electric cooperative members of Soyland:

Clinton County, McDonough, Corn Belt, Southwestern, Farmers Mutual, Tri-County, Illinois Valley, Monroe County.

(2) Effective January 1, 1984, Mt. Carmel transferred to a full requirements wholesale Purchase Power Agreement. (FERC Rate Schedule No. 87)

(3) IP has had no changes in its service area since the submission of the construction permit application.

(4) IP has had no acquisitions or mergers since the submission of the construction permit application.

Soyland - None

WIPCO - None

B.1.g - List of those generating capacity additions committed for operation after the nuclear facility, including ownership rights or power output allocations.

Responses:

IP - None

Soyland - None

WIPCO - None

B.1.h - Summary of requests or indications of interest by other electric power wholesale or retail distributors, and licensee's response, for any type of electric service or cooperative venture or study.

Responses:

IP - Since the submission of the construction permit application, IP has studied proposals to purchase or to provide electric service on an interconnection or wholesale basis to the following:

(1) Proposals to Purchase

(a) Cedar Point Light and Power Company contacted early in 1981, relative to a possible sale of their system to IP. Merger discussions between Cedar Point and IP have been held since 1981 and the parties are in the process of negotiating a stock exchange to merge the two systems.

(b) The City of Riverton, Illinois contacted IP in November, 1980, requesting a bid on their electric system. IP made a study of Riverton's system but no offer to purchase it was made because the City suspended negotiations.

(c) IP and Mt. Carmel Public Utility Co. executed a stock exchange merger agreement late in 1981. On December 7, 1981, this merger agreement was filed with the ICC for approval. CIPS intervened and protested the proposed merger. On November 23, 1982, the ICC entered an order denying the IP-Mt. Carmel petition for a merger. A request for a rehearing by IP and Mt. Carmel was denied. On February 2, 1983, IP filed a Notice of Appeal, Case No. 83 MR5 in the Second Judicial Circuit Court, Wabash County. Mt. Carmel filed its appeal in the same Court on February 3, 1983. CIPS filed its Motion for Leave to Enter Appearance and File

Petition to Intervene Instanter in the case on February 22, 1983. On December 14, 1983, the Circuit Court issued a ruling, upholding the ICC Order. IP and Mt. Carmel filed a Notice of Appeal of the Circuit Court ruling with the 5th District Appellate Court in Mt. Vernon, Illinois on January 13, 1984, where the case is pending.

An Application for Merger of IP and Mt. Carmel was filed with FERC on December 14, 1981. (FERC Docket No. EC82-4-000). The application is pending before FERC.

(d) The City of Carmi, Illinois, contacted IP in August, 1981, requesting a proposal to purchase the system. Negotiations were suspended by the City prior to IP making a proposal.

(2) Requests for Interconnection or Wholesale Service:

(a) Village of Chatham, Illinois, preliminary inquiries.

(b) Village of Flora, Illinois, preliminary inquiries.

(c) City of Red Bud, Illinois, preliminary inquiries.

(d) Wabash Valley Power Association, Inc., preliminary inquiries.

(e) Southern Illinois Power Cooperative, Inc. (See IP response to B.1.b)

(f) Farmer City (See IP response to B.1.f)

(g) WIPCO (See IP response to B.1.c(2)(b) and (c).

(h) IP, Soyland and WIPCO are currently studying the benefits for joint participation in IP's existing fossil-fired generating units. (See Soyland and WIPCO responses below to B.1.h(2))

Soyland - Soyland, WIPCO, and Illinois Power are currently studying the benefits, if any, for joint participation in existing Illinois Power fossil units.

WIPCO - WIPCO is participating with Soyland Power Cooperative and Illinois Power Company in a power supply study to determine the benefits, if any, for joint participation in Illinois Power Company's existing fossil-fired units.

B.2 - Licensees whose construction permits include conditions pertaining to anti-trust aspects should list and discuss those actions or policies which have been implemented in accordance with such conditions.

Response:

In Appendix A of his letter to Joseph Sanders, Esq., Chief Public Counsel and Legislative Section, Anti-trust Division, U. S. Department of Justice, Mr. W. C. Gerstner (IP Executive VP) expressed the "STATEMENT OF POLICY CONCERNING BULK POWER SUPPLY ARRANGEMENTS WITH NEIGHBORING ELECTRIC SYSTEMS IN CONNECTION WITH CLINTON POWER STATION UNITS 1 AND 2".
In compliance with that Policy, Illinois Power Company has entered into the following agreements:

(1) Joint Ownership of Clinton Unit 1 with Soyland, (Soyland Power Cooperative, Inc.) and WIPCO (Western Illinois Power Cooperative, Inc.) (10.5% and 9.5%, respectively).

(2) Interconnection and Facility Use Agreements with both Soyland and WIPCO.

(3) Interconnection Agreement with Springfield-City Water Light & Power (CWL&P)

In addition, Illinois Power Company has investigated the possibility of service on an interconnection or wholesale basis with several municipalities as shown in items B.1.f(1) and B.1.h above.

List of Exhibits

IP-1 IP Projected Capacity and Demand at System Peak for the years 1984 through 1993.

IP-2 Illinois Power Co. Supplemental Interruptible Electric Service schedule with interconnected municipalities

IP-3 Illinois Power Co. Rider 5 - Supplemental Interruptible Electric Service.

IP-4 Agreement for Purchase of Power From Illinois Power Company by Western Illinois Power Cooperative, Inc.

IP-5 Short Term Energy Transmission Agreement.

IP-6 Electric Transportation Service Agreement.

IP-7 Illinois Commerce Commission Order, Dockets 80-0544 and 80-0365.

IP-8 Illinois Commerce Commission Order, Docket 82-1052.

IP-9 Illinois Power Company - Schedule of Rates for Electric Service.

W-1 Estimated Capacity Requirements and Available Capacity for WIPCO in MWe 1983 through 1993.

Illinois Power Company
Projected Capability and Demand at System Peak
(Megawatts)

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Units Added				760						
Owned Capacity	3742	3742	3742	4502	4502	4502	4502	4502	4502	4464 1/
Joppa Capacity	203	203	203	203	203	203	203	203	203	203
System Capacity	3945	3945	3945	4705	4705	4705	4705	4705	4705	4667
Unreserved Purchases										
North Counties Hydro	2	2	2	2	2	2	2	2	2	2
Unreserved Sales										
Joppa Demand	-148	-148	-148	-148	-148	-148	-148	-148	-148	-148
Adjusted Capability	3799	3799	3799	4559	4559	4559	4559	4559	4559	4521
Net System Demand	3110	3158	3206	3178	3228	3282	3340	3395	3450	3510
Reserved Sales										
Soyland				15	15	15	15	15	15	15
WIPCO Turris	4	4	4							
Reserved Purchases										
TVA	-65									
Adjusted Demand	3049	3162	3210	3193	3243	3297	3355	3410	3465	3525
Reserve with Scheduled Units	750	637	589	1366	1316	1262	1204	1149	1094	996
Percent Reserve (%)	24.6	20.1	18.3	42.8	40.6	38.3	35.9	33.7	31.6	28.3

1/ Reflects a 38 MW derating due to flue gas desulfurization equipment installation.

EXHIBIT IP-1

2/21/84

Supplemental Interruptible Electric Service

1. Availability

Service is available to any customer located in territory served by Utility subject to the following conditions:

(a) that Customer takes firm service under Agreement for Purchase of Power from Illinois Power Company (Agreement);

(b) that prior to the commencement of service Customer shall enter into a written agreement with Utility and specify a Supplemental Interruptible Capacity.

2. Conditions of Service

(a) Supplemental Interruptible Electric Service is interruptible electric service provided to Customer in addition to service provided under the Agreement. The provision of Supplemental Interruptible Electric Service is subject to unlimited interruptions and curtailments by Utility and shall be subject to interruptions prior to curtailment of service to any of Utility's customer taking service under Service Classification 30. The capacity required to provide Supplemental Interruptible Electric Service shall be referred to as Supplemental Interruptible Capacity. Whether or not notice is received by Customer in advance of any interruption or curtailment, Utility shall have no liability to Customer, and Customer shall assume full responsibility for any loss, damage or claim (including but not limited to product loss and loss of profits) by reason of any interruption, curtailment or restoration of service.

(b) Supplemental energy shall be defined for billing purposes as all energy used by Customer during the on-peak period defined in Customer's Wholesale Electric Service Agreement in excess of Customer's contract capacity.

(c) Supplemental Interruptible Electric Service shall not be available during periods in which service to Utility's customers taking service under firm or limited firm service classification is curtailed.

(d) Firm Power is that demand and energy for which Customer has contracted for under Article II, Section 1 of the Agreement at the same point of delivery as Supplemental Interruptible Electric Service. Customer shall pay each month, in addition to the charges in subsections 3(a) and 3(b), the charges specified under Wholesale Electric Service Agreement for which firm power was contracted.

3. Rates

The gross charge shall equal the sum of the charges below and other applicable charges under the Wholesale Electric Service Agreement, increased by two percent.

(a) Supplemental Interruptible Electric Service

(1) Demand Charge

Customer shall pay no Contract Capacity charge or Capacity Reservation charge for Supplemental Electric Service unless Customer's maximum 15 minute demand established during a period of interruption exceeds the load limit specified by Utility plus the maximum amount of firm power for which Customer has contracted. Customer shall pay to Utility for each such occurrence (in addition to the rates provided herein) an amount equal to $4.34, $3.79 or $3.09 per kva based on the applicable delivery voltage, multiplied by the number of kva of such excess, and Customer's contract capacity will be increased, without notice or other action, by the amount of such excess kva. In the event Customer is provided service under the provisions of the Interim Wholesale Electric Service Agreement, the contract capacity will be the June 15, 1980 kva nomination stated in subsection 2(c) of said agreement.

(2) Energy Charge

The energy charge for Supplemental Interruptible Electric Service shall be determined as follows:

(i) During periods in which Utility anticipates operating generating units having a heat rate greater than 15,000 Btu's per kwh or purchasing energy under the emergency provisions of its interchange agreements, the charge shall be 6.10¢ per kwh.

(ii) During all other periods, the charge shall be determined in accordance with the provisions of subsection 3(c) of the Wholesale Electric Service Agreement.

(b) Cost of Power Adjustment

The schedule of charges set forth above is subject to the Cost of Power Adjustment provided in subsection 3(d) of the Wholesale Electric Service Agreement.

4. <u>Interruptions, Curtailments and Notifications</u>

(a) Utility shall have the right to make any interruption or curtailment without notice to Customer. Utility, however, will attempt to provide Customer with two hours notice of any interruption or curtailment or when the energy charge in subsection 3(a)(2)(i) of this Exhibit E is in effect, but Utility shall have no obligation to give such advance notice or to assume any liability for failure to do so.

(b) Notice of interruption or curtailment or when the energy charge in subsection 3(a)(2)(i) of this Exhibit E is in effect may be given by telephone from Utility. Customer shall designate a representative to Utility to whom such notice of an interruption or curtailment can be provided.

(c) Utility may agree to permit an interruption procedure to be carried out by Customer's personnel, provided all steps in such procedure are subject to control by Utility. Customer shall provide, at Customer's expense, a direct line telephone connection between Utility's supply dispatch office and Customer's dispatch office upon six (6) months written notice by Utility.

(d) After any interruption or curtailment of service, Customer shall not reconnect any load to Utility's system without approval from Utility.

Exhibit IP-3
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ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

RIDER S
Supplemental Interruptible Electric Service

*1. Availability

Service is available to any customer located in territory served by Utility subject to the following conditions:

(a) that Customer takes firm service under Utility's Service Classification 21 - Large Power Service with a contract capacity of at least 1000 kw or Service Classification 24 - Annual Load Factor Large Power Service, and

(b) that service is not available under this Rider if the utilization of service is of such character that service cannot be interrupted or curtailed at any time by utility without loss to customer or damage to property or persons and without adversely affecting the public health, safety or welfare, and

(c) that Utility may limit service under this rider to 50 customers, and

(d) that prior to the commencement of service Customer shall enter into a written agreement with Utility and specify a Supplemental Interruptible Capacity.

2. Conditions of Service

(a) Supplemental Interruptible Electric Service is interruptible electric service provided to Customer in addition to service provided under a firm service classification. The provision of Supplemental Interruptible Electric Service is subject to unlimited interruptions and curtailments by Utility during the on-peak periods of both summer and winter seasons. The capacity required to provide Supplemental Interruptible Electric Service shall be referred to as Supplemental Interruptible Capacity. Whether or not notice is received by Customer in advance of any interruption or curtailment, Utility shall have no liability to Customer, and Customer shall assume full responsibility for any loss, damage or claim (including but not limited to product loss and loss of profits) by reason of any interruption, curtailment or restoration of service.

(b) Supplemental energy shall be defined for billing purposes as all energy used by Customer during the on-peak period defined in Customer's firm service classification in excess of Customer's contract capacity or capacity reservation.

(c) Supplemental Interruptible Electric Service shall not be available during periods in which service to Utility's customers taking service under firm or limited firm service classification is curtailed.

(d) Firm Power is that demand and energy for which Customer has contracted for on a firm basis under an applicable service classification at the same point of delivery as Supplemental Interruptible Electric Service. Customer shall pay each month, in addition to the charges in subsection 3(a) and 3(b), the charges specified under the service classification for which firm power was contracted.

*3. Rates

(a) Supplemental Interruptible Electric Service

(1) Demand Charge - Customer shall pay $.10 per billing period for each kw of Supplemental Interruptible Capacity during all billing periods.

In the event Customer's maximum 15 minute demand during a period of interruption exceeds the load limit specified by Utility plus the amount of firm power for which Customer has contracted, Customer shall pay to Utility for each such occurrence (in addition to the charges provided in the customer's applicable service classification) an additional amount equal to the demand charge in the applicable service classification multiplied by the number of kw of such excess, and the amount of firm power for which Customer has contracted will be increased, without notice or other action, by the amount of such excess kw.

*Asterisk indicates change.

Exhibit IP-3
Page 2 of 3

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

RIDER S - PAGE 2

*3. Rates (continued)

(2) Energy Charge

The energy charge for Supplemental Interruptible Electric Service shall be determined as follows:

(i) During periods in which Utility anticipates operating generating units having a heat rate greater than 15,000 Btu's per kwh or purchasing energy under the emergency provisions of its Interchange Agreements, the charge shall be 6.10¢ per kwh.

(ii) During all other periods, the charge shall be determined in accordance with the provisions of subsection 3(b) of the service classification under which Customer takes firm service.

(b) Fuel Cost Adjustment

The schedule of charges set forth above is subject to the Fuel Cost Adjustment provided in Rider E. The Fuel Cost Adjustment shall be calculated and applied separately for each month only to the actual kwh used by Customer during the month.

*4. Adjustment of Maximum On-Peak Demands For Billing Purposes

In the event that Customer's maximum on-peak demand exceeds the amount of firm power for which Customer has contracted, the demand for billing under Customer's applicable service classification shall be Customer's maximum on-peak demand less the Supplemental Interruptible Capacity to the extent not curtailed but not less than the amount of firm power demand contracted for under Customer's applicable service classification.

*5. Adjustment of Firm Power Contract Capacity or Capacity Reservation

The amount of firm power determined according to the provisions of customer's applicable service classification shall be adjusted to the greater of the following:

(a) Customer's maximum on-peak demand from June 15 through September 14 less the amount of Supplemental Interruptible Capacity allowed by Utility during a period of curtailment.

(b) Customer's maximum on-peak demand from June 15 through September 14 less the customer's Supplemental Interruptible Capacity during a period with no curtailment.

*6. Interruptions and Curtailments

(a) Utility shall have the right to make any interruption or curtailment without notice to Customer. Utility, however, will attempt to provide Customer with two hours notice of any interruption or curtailment, but Utility shall have no obligation to give such advance notice or to assume any liability for failure to do so.

(b) Notice of interruption or curtailment may be given by telephone from Utility. Customer shall designate a representative to Utility to whom notice of an interruption or curtailment can be provided.

(c) Utility may agree to permit an interruption procedure to be carried out by Customer's personnel, provided all steps in such procedure are subject to control by Utility. Customer shall provide, at his expense, a direct line telephone connection between Utility's Supply Dispatch office and Customer's dispatch office.

(d) After any interruption or curtailment of service, Customer shall not reconnect any load to Utility's system without approval from Utility.

*Asterisk indicates change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

7. Additional Conditions and Contract Provisions

(a) Customers taking supplemental interruptible service under this Rider shall contract for and take service for a primary term of twelve (12) months. The primary term or extended term of any contract shall be automatically extended from year to year with the privilege of either party to terminate the contract at the end of the primary term or during any extended term on not less than 30 days written notice.

(b) Utility may agree to increase customer's firm power for which customer has contracted at any time provided customer has given utility not less than twenty-four (24) hours notice before such increase shall become effective.

EXHIBIT IP-4

AGREEMENT FOR PURCHASE OF POWER

FROM ILLINOIS POWER COMPANY

BY

WESTERN ILLINOIS POWER COOPERATIVE, INC.

DATED: May 24, 1983

CONTENTS

APPENDIX

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AGREEMENT FOR PURCHASE OF POWER

FROM ILLINOIS POWER COMPANY

This is an Agreement For Purchase of Power dated as of May 24, 1983, between ILLINOIS POWER COMPANY ("Company"), and the Western Illinois Power Cooperative, Inc. ("Customer").

Company is an Illinois corporation with its business office at 500 South 27th Street in Decatur, Illinois, is engaged in the generation, transmission, distribution and sale of electric energy to the public in various municipalities and areas in the State of Illinois, and is a public utility within the meaning of an Act entitled "An Act Concerning Public Utilities," approved June 29, 1921, as amended, set forth in Chapter 111-2/3, Section 1 et. seq. of the Illinois Revised Statutes, and now in force.

Customer owns and operates electric utility facilities and provides electric service to its member electric cooperatives.

Customer desires to purchase electric energy at wholesale for its use and for resale to its member cooperatives, and Company desires and is willing and able to supply Customer with electric energy for these purposes, on the terms and conditions hereinafter set forth.

In consideration of the mutual agreements herein contained, the parties agree as follows:

I. General Terms

Company shall supply electric energy and Customer shall accept and pay for service rendered under the terms of Exhibit A attached hereto, and made a part hereof, entitled Wholesale Electric Service Schedule. Agreement shall control if there is any conflict between it and the provisions of Exhibit A.

Company shall render utility service for all of Customer's requirements in those areas indicated on the Service Area Map, marked as Exhibit B.

II. Conditions of Service

1. Company agrees to supply and Customer agrees to accept electric energy at points of delivery as follows:

   (a) Existing Points of Delivery

   Existing Points of Delivery are defined as those existing points of delivery at which electric energy is being supplied on the effective date of this Agreement and are set forth under such

designation on Exhibit C attached hereto. Energy shall be supplied and accepted under the terms so specified with reference to each existing delivery point on Exhibit C.

(b) <u>Anticipated Future Delivery Points</u>

Anticipated Future Delivery Points are defined as specific delivery points which Customer anticipates will be required during the term of this Agreement.

Such points are set forth under such designation on Exhibit C attached hereto. Company agrees, upon notification by Customer that it desires a supply of energy at any one or more of said points, to promptly provide such supply under the terms specified herein. Upon initiation of service at any such point, the reference to each such point will be relocated under the proper heading on Exhibit C.

Customer shall, by December 1 of each year, provide Company with Customer's contemplated power requirements at each existing and anticipated point of delivery listed on Exhibit C for each of the next three calendar years. Such schedule shall not itself be deemed to be a request for capacity at a particular delivery point.

(c) <u>Unanticipated Future Delivery Points</u>

Company will also provide Customer with power at additional points of delivery along Company's lines if available in such lines and the point of delivery requested is reasonably satisfactory from the standpoint of Company's system operations. No such additional delivery point shall be within 5 miles of an Existing or Anticipated delivery point of Customer listed on Exhibit C.

The distance of 5 miles shall be determined by measuring along the transmission line serving such Existing or Anticipated delivery point if the additional delivery point will be served by the same transmission line, and if not, by the distance between the Existing or Anticipated delivery point and the additional delivery point measured along a route which would be practical from an engineering standpoint for the construction of a transmission line between such points.

2. All energy delivered by the Company to Customer, in accordance with Company's normal requirements, shall pass either through suitable fuses or suitable circuit breakers to be installed and maintained by Customer as

near as practicable to each point at which energy is delivered, and the installation of all lines and equipment of the Customer over which energy shall be transmitted, up to and including Customer's circuit breakers or fuses, and the interrupting rating of fuses and circuit breakers, relay settings and fuse sizes, shall be coordinated with the Company's facilities. Company shall notify Customer at the earliest practicable date of any changes in fault current or operating practices on Company's system affecting coordination on Customer's system and Customer's responsibility. However, the requirements for the installation of protective equipment upon Customer shall not be more stringent than would be imposed on Company by its system operating policies in comparable circumstances.

3. Customer shall extend its line to the point of delivery from Company. Company shall make the connection and furnish and install meters, recording devices and other apparatus necessary for the measurement of energy received by Customer from Company. Customer will provide a suitable location for the metering.

4. Customer agrees to use reasonable care to design its circuits so that loads of individual phases on its lines at the point of delivery will be balanced as nearly as practicable.

5. Customer and Company agree to maintain and operate their systems in accordance with sound engineering and operating practices, so as to minimize the likelihood of a disturbance in either system which might cause impairment of service to the other party's system.

III. Rates and Charges

1. Customer agrees to pay Company monthly for electric service rendered during the preceding month at the rates and charges due and payable therefor as provided in the Schedule attached as Exhibit A or as subsequently revised under Section X, paragraph 3.

2. Company shall add to all charges under this Agreement and those provided for in Exhibit A the amount of any existing tax or charge of any kind levied, assessed, or charged by any municipal, state, or federal government, or authority becoming effective after the execution date of this Agreement, measured by but not included in the purchase price paid or revenues received by Company on account of the service rendered under this Agreement.

IV. Rate Renegotiations

1. After September 1, 1983, subject to the provisions of

paragraph (e) of this Section IV, either party, by written notice given to the other party, may request negotiations for the purpose of establishing a new rate for the electric energy to be supplied under this Agreement. This request must contain the rate the requesting party proposes. After such notice, both parties shall promptly and in good faith engage in negotiations for this purpose, and each party shall make available promptly to the other party all information which that party may reasonably request for the purpose of the negotiations.

2. If, after a reasonable period which shall not exceed 12 months, the parties for any reason have not agreed to a new rate, the negotiations shall automatically terminate unless extended by mutual agreement of the parties. In the event negotiations are terminated, the party requesting the negotiations may seek the establishment of its proposed new rate by an appropriate filing with or complaint or application to an appropriate regulatory agency deemed by the party making the filing, complaint or application to have jurisdiction of determination of wholesale rates of Company and a copy of such filing, complaint or application shall be furnished to the other party, provided nothing in this Agreement shall be deemed to constitute any waiver of the right of either party to object to the jurisdiction of the regulatory agency to which the filing, application or complaint is made by the other party. In the case of a filing of a proposed new rate by Company, such rate shall become effective in accordance with the procedure for the filing of rate changes provided for by Section 205 of the Federal Power Act, as amended, or as permitted by such other law or laws as may become applicable to the rates charged under this Agreement.

3. In case of any filing with or proceeding before a regulatory agency under this Section IV, the party which requested negotiations shall not seek thereby to establish a new rate more advantageous to it than the rate which it proposed at the time negotiations were requested, nor a retroactive effective date, nor shall it seek changes in the other provisions of this Agreement. Such party also agrees that it will not directly urge the approval by such agency of any other rate more advantageous to it, or other change in this Agreement without the written consent of the other party first obtained. Except as to the rate initially proposed in such negotiations and the fact that such negotiations have been held and no agreement reached, all other rates, if any, and other matters submitted in such negotiations by either party shall be deemed to have been submitted in connection with the possible settlement of the issue and shall not constitute proof or admission of any fact or otherwise be admissible in

evidence in any rate proceeding, without first obtaining the consent of the party submitting such fact or evidence in the negotiations.

4. If any rate or effective date of such rate as finally determined by the regulatory agency having jurisdiction thereof is deemed unsatisfactory by either party, such party at its option may elect to terminate this Agreement on notice to the other in writing given within 60 days after such determination becomes final, effective on January 1 of a specified year which shall be not less than three years from the date of such notice; provided, however, that this provision shall not limit the right of either party to terminate this Agreement as may in this Agreement otherwise be specified herein.

5. If either party shall request negotiations for the purpose of establishing a new rate, that party shall not have the right to make another such request until after the expiration of 12 months following the month in which the previous request was made.

V. Meter Reading and Billing

1. Company shall read meters and render bills monthly. Bills will be rendered at a net charge using the rates and charges contained in Exhibit A in effect at the time, including other charges in this Agreement. Bills will be rendered three days from reading date, and payment shall be due fifteen days from the date of rendering the bill. Accounts not paid in full within the net payment period will be subject to an additional charge of 2 percent.

2. Should either over-billing or under-billing occur due to causes other than inaccurate meter registration, it shall be corrected by proper allowance or payment upon written notice by either party to the other, by mail or by personal delivery, provided that such notice must be given within one year following the date on which the bill to be corrected is rendered.

3. If Customer has failed to pay any bill accruing under this Agreement on or before the thirtieth day after day of billing, Company may discontinue delivery of electric energy provided at least fifteen days prior written notice has been given to Customer. Company will not be liable in any manner for any loss or damage arising from such discontinuance of electric service.

VI. Metering, Testing and Billing Adjustments

1. Company shall own and maintain the meters and related metering equipment necessary to measure the demand and energy delivered to Customer by Company at the point

of delivery.

2. Company shall test and calibrate the meters by comparison with accurate standards at approximate twelve month intervals.

3. Company shall make special meter tests at the written request of Customer. If a special test made at Customer's request shall disclose that meters are registering within 2 percent of 100 percent accuracy, Customer shall bear the expense of the test; otherwise, the cost of such test shall be borne by Company. Company shall give Customer three days advance notice of its intention to test and calibrate meters when such test is requested in writing by Customer. Customer shall be permitted to witness any meter tests made by Company.

4. Meters found by test to be registering inaccurately shall be restored to a condition of accuracy. If the inaccuracy exceeds two percent, the meter readings taken during the period 90 days preceding (or during such shorter period as may have intervened since the previous test) shall be corrected by the percentage of inaccuracy found by the test and billing adjusted accordingly. No prior readings will be corrected.

5. Company, upon Customer's request, shall provide Customer within a reasonable time after the end of the billing period and at least by the due date of the bill rendered, a written record of the successive 15 minute demands established by Customer at each delivery point.

6. Customer may at its own expense install and maintain additional metering equipment for the purpose of checking the meters installed by the Company, and the readings thereof. Customer shall be solely responsible for the comparative accuracy of its own metering equipment. Upon request of Customer, Company will modify, at Customer's expense, its demand recording equipment to make available to Customer parallel but isolated electrical contacts which Customer may use to drive its own demand recording equipment.

7. If the meters installed by the Company wholly fail to register the energy during any period of time, the amount of energy delivered during such period will be measured by means of the meters installed by the Customer, and if the Customer has not so installed meters, or if its meters have wholly failed to register during this period of time, the amount of energy so delivered shall be estimated and agreed to by the Company and Customer based upon amounts previously delivered under substantially similar conditions.

8. Electric energy supplied hereunder to Customer for use by the Customer or its member cooperatives in carrying on its, or their, business of supplying electricity to its member cooperatives, or their members, as the case may be shall be metered at delivery voltage, which for this purpose may be less than 34,500 volts.

VII. Rights of Access

Duly authorized representatives of either party hereto shall be permitted reasonable access to the premises of the other party if required to carry out the provisions of this Agreement. Each party shall have access to the facilities of the other party at a mutually agreed-upon time for the purpose of removing its own facilities from the facilities of the other party where such removal is permitted under this Agreement.

VIII. Continuity of Service

1. Company agrees to provide adequate and reliable service to Customer. However, Company shall not be liable to Customer for interruption or inadequacy of service, loss or damage to property, or injury (including death) to any person caused by act of God, public enemy, vandalism, strikes and other labor troubles or their equivalent, legal process, state, municipal or other governmental regulation, windstorm, flood, fire or explosion, or other matter or thing beyond Utility's control, whether the same shall affect or occur in connection with the operations or property of Customer, Company or any other person including Customer's member cooperatives.

2. Company shall not be responsible for damages due to any failure to supply electricity, or for interruption, or reversal of the supply, if such failure, interruption, or reversal is without willful default or negligence on its part, nor for interruptions, by underfrequency relays or otherwise, to preserve the integrity of Utility's system or interconnected systems.

3. Company may interrupt service to make necessary repairs or to make changes in equipment or to install new equipment, but only for such reasonable times as may be unavoidable. If the nature of the situation permits, reasonable advance notice of these interruptions shall be given by Company.

IX. Liability

1. Customer shall not be liable, and Company shall save Customer harmless against any and all claims, damages, liability or expense, resulting from or occasioned by the presence, use or maintenance of any electrical conductor or other type of equipment owned or

maintained by Company or Customer or by the escape of electric energy in or from any such conductor or equipment, provided that such claims, damages, liability or expense shall be caused by Company's negligence or misconduct.

2. Company shall not be liable, and Customer shall save Company harmless against any and all claims, damages, liability or expense resulting from or occasioned by the presence, use or maintenance of any electrical conductor or other type of equipment owned or maintained by Company or Customer, or by the escape of electric energy in or from any such conductor or equipment, provided that such claims, damages, liability or expense shall be caused by Customer's negligence or misconduct.

3. Negligence or misconduct, as used herein, shall include but not be limited to failure to comply with all General Orders of the Illinois Commerce Commission applicable to the furnishing of electric service by Company or customer, all regulations of the United States Occupational Safety and Health Administration and the Structural Work Act of the State of Illinois, or failure to meet any standard of care derived from any of such orders, regulations or statute, provided that such failures to comply with the foregoing Orders, regulations or acts or any standard of care derived therefrom shall have caused or created, in whole or in part, the damage or loss.

X. Term of Agreement

1. This Agreement shall be for a term of three years commencing with the effective date of this Agreement. The Agreement shall continue thereafter from year to year unless cancelled by either party at the expiration of the primary or extended term upon not less than one year prior written notice. However, in any event this Agreement shall terminate upon commercial operation of Clinton Nuclear Unit No. 1.

2. All provisions of this Agreement which are obligatory upon or shall inure to the benefit of Company shall be obligatory upon and inure to the benefit of all successors and assigns of Company. Also all provisions of this Agreement are obligatory upon or shall inure to the benefit of Customer shall be obligatory upon and inure to the benefit of all successors and assigns of Customer.

3. Nothing contained herein shall be construed as affecting in any way the right of either party under this Agreement to unilaterally make application to the Federal Energy Regulatory Commission or any successor agency for a change in rates set forth in Exhibit A

attached hereto under Section 205, or any similar provision, of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder or under any other applicable federal law or commission.

XI. **Approval**

This Agreement shall not be binding upon either party until approved by the Administrator of the Rural Electrification Administration and by any regulatory body which may have jurisdiction thereof, if approval of any such body is required.

IN WITNESS WHEREOF, the parties have duly entered into this Agreement as of the day and year first above written but actually executed on 24th day of May, 1983, to an original and two copies all of which are considered to be duplicate originals.

ILLINOIS POWER COMPANY	WESTERN ILLINOIS POWER COOPERATIVE, INC.
By Larry D. Haab	By Kenneth Marlow
Title Vice President	Title President
Date May 20, 1983	Date May 24, 1983
Attest:	Attest:
As to Illinois Power Company (Secretary)	As to Western Illinois Power Cooperative, Inc.

CCOPR3-W

Wholesale Electric Service Schedule

1. Availability

Service hereunder is available to the Western Illinois Power Cooperative, Inc. ("Customer") from Illinois Power Company (Company) subject to the following conditions:

a. That Customer is engaged in the generation, transmission, and sale of electricity to its member cooperatives;

b. That Customer is supplied from Company's lines having a capacity adequate to supply Customer's requirements in addition to the requirements of other customers already receiving service from such lines;

c. That prior to the commencement of service hereunder, Customer shall execute and shall thereafter keep in full force and effect a written agreement with Company.

2. Conditions of Service

Service hereunder shall be provided to Customer subject to the following conditions:

a. Should Customer desire to receive electric energy from any source other than capacity owned and operated by Customer and to operate in parallel with the power supplied by Company to Customer under this schedule, it shall, in the absence of existing arrangements with Company for the delivery of such power, give the Company reasonable notice of such desire, specifying the requirements involved and the date when it desires parallel operation to commence. Reasonable notice shall be defined as notice sufficient to allow Company to continue safe and efficient operation of its system and shall be interpreted in an engineering context considering the facilities and requirements involved;

b. Company shall be reimbursed for any expenses incurred by reason of the addition of an alternate source of electric energy as referred to in subsection 2(a);

c. Service hereunder will be initially delivered to Customer from electric lines having capacity sufficient to serve Customer's energy requirements. Company retains discretion to select the supply line or lines from which service will be rendered to Customer. The supply line selected shall be the best available source with adequate capacity based on good engineering practices. Company also retains discretion to change such supply line or lines and to change the voltage of the supply line or

2. Conditions of Service (continued)

lines or other conditions of service. If such change is initiated by Company, the cost of providing service under the new conditions including the cost of transformation shall be borne by Company. In all other cases, except for changes caused by an increase in Customer's electric energy requirements which shall be governed by Section II of the Agreement for Purchase of Power between the parties, costs of changes shall be borne by Customer;

d. Customer shall provide and maintain all transformers and related facilities necessary for handling and utilizing the energy delivered hereunder;

e. Company will provide and maintain three-phase voltage connections, provided Customer will make available, without charge to Company, space required for Company's lines and delivery facilities, and;

f. Company will provide and maintain delivery points and metering equipment therefor. Such metering equipment shall be located on the high voltage side of Customer's transformation. Company, at its discretion, may elect to install such metering equipment on the low voltage side of transformation (whether or not for the convenience of Company or Customer) and in such case, both the demand and energy consumption will be increased to compensate Company for transformer losses as measured by such metering equipment, or in the absence of such measurement, by computing such losses based on the manufacturer's data pertaining to the specific transformers installed.

3. Rates and Charges

The monthly charge shall equal the sum of the charges below and any other applicable charges.

a. Demand Charge:

Delivery Voltage	Charge per Kva of Billing Demand in any One Month
4160 or 12,470 volts	$4.26
34,500 or 69,000 volts	$3.76

b. Energy Charge:

2.60¢ per Kwh for all Kwh delivered by Company in any one month.

3. Rates and Charges (continued)

c. Cost of Power Adjustment:

(1) A Cost of Power Adjustment (CPA) will be applied to each Kwh of energy billed hereunder during the "billing period" as defined herein.

(2) $$CPA = \frac{(FCCG + ECPP + ECIP - FCIS) \times 100}{(CG + PP + IP - IS) \times LF} - 1.70¢$$

Where:

CPA = Cost of Power Adjustment. The amount rounded to the nearest .001¢ per Kwh to be charged for each Kwh billed hereunder during any monthly "billing period" as defined herein.

FCCG = Fuel Cost of Company Generation. The cost of fossil fuel as included in Account 151 and the cost of nuclear fuel as included in Account 518, according to the FPC Uniform System of Accounts, consumed in "Company's plants" during the "determination period."

ECPP = Energy Cost of Purchased Power. The net energy cost of energy purchased on an economic dispatch basis from other utilities under purchased power agreements during the "determination period," exclusive of capacity or demand charges. Otherwise, the actual identifiable fuel cost associated with such energy purchased.

ECIP = Energy Cost of Interchange Purchases. The net energy cost of energy purchased on an economic dispatch basis from other utilities during the "determination period" under interchange or interconnection agreements irrespective of the designation assigned to such transactions. Otherwise, the actual identifiable fuel cost associated with such energy purchased.

FCIS = Fuel Cost of Interchange Sales. The cost of fuel consumed in "Company's plants" to generate energy sold to other utilities during the "determination period" through all inter-system sales.

3. Rates and Charges (continued)

CG = Company Generation. All Kwh generated during the "determination period" in Company's plants.

PP = Purchased Power. All Kwh purchased, except interchange purchases, from other utilities during the "determination period" irrespective of the designation of such purchases.

IP = Interchange Purchases. All Kwh purchased or received from other utilities during the "determination period" under interchange or interconnection agreements irrespective of the designation of such purchases.

IS = Interchange Sales. All Kwh generated in "Company's plants" which were sold or furnished to other utilities during the "determination period" through all inter-system sales.

LF = Loss Factor. The estimated ratio of Kwh sales at the average delivery voltage of wholesale sales for resale to the Kwh generated for such sales. This ratio is .97.

(3) Definitions

(a) The "determination period" is defined as the calendar month immediately preceding the billing period.

(b) The "billing period" is defined as the period beginning with the 4th billing cycle of the month following the "determination period" and ending with the 3rd billing cycle of the next month.

(c) "Company's plants" is defined as Company's fossil and nuclear generating plants and Company's share of any jointly owned or leased fossil and nuclear generating plants.

4. Determination of Demands

a. Maximum on-peak Kva demand for each point of delivery will be the highest number of Kva delivered during any fifteen minute on-peak period for the billing period at such point of delivery hereunder.

b. The on-peak period is the 11 consecutive hours commencing at 10:00 a.m. and ending at 9:00 p.m. on Monday through Friday excluding New Year's Day, Good Friday, Memorial Day (May 30), July 4, Labor Day, Thanksgiving Day, Christmas Eve Day, and Christmas Day.

c. Billing demand for any billing period shall be the sum for all points of delivery hereunder or the greater of the following at each such point of delivery:

(i) The maximum on-peak Kva demand measured during the billing period, or

(ii) 75 percent of the maximum on-peak Kva demand established during the period June 15 through September 14 of the previous twelve months.

d. The maximum on-peak Kva demand established at any delivery point will be adjusted for temporary or permanent transfers of load from one delivery point supplied by Company to another delivery point supplied by Company.

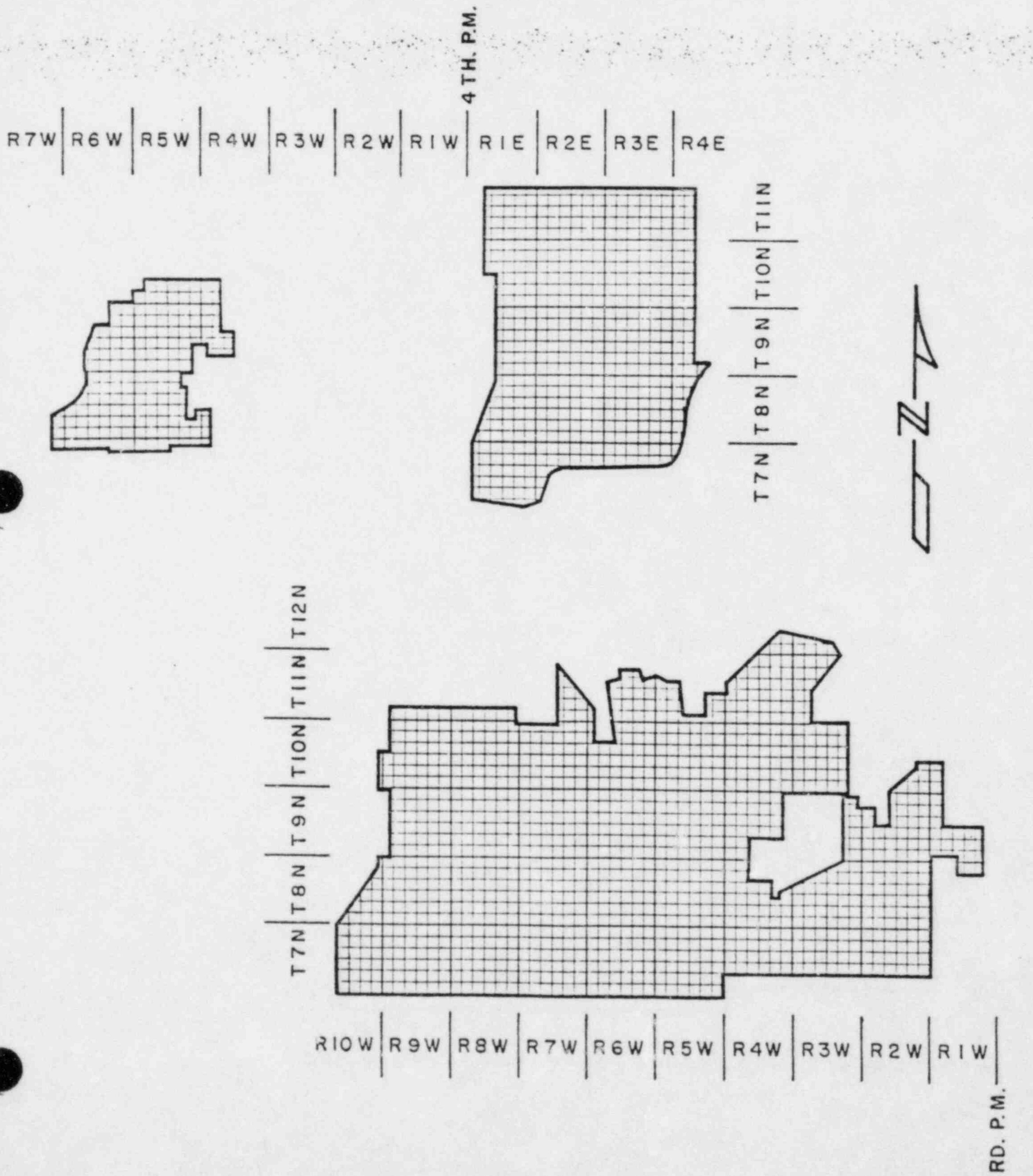
5. Additional Conditions and Contract Provisions

a. If Customer requires service at any delivery point specified in Exhibit C for existing, new or added capacity which requires Company to install special apparatus, Customer shall execute and keep in full force and effect a written contract with Company for service which shall specify terms and conditions of service not inconsistent with those provided for herein.

b. Nothing contained herein shall be construed as affecting in any way the right of either party under this rate schedule to unilaterally make application to the Federal Energy Regulatory Commission or any successor agency for a change in rates set forth in Section 3 hereof under Section 205, or any similar provision, of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder or under any other applicable federal law or commission.

EXHIBIT B

PURSUANT TO SECTION I OF
AGREEMENT FOR PURCHASE OF POWER
BY WESTERN ILLINOIS POWER COOPERATIVE, INC.
FROM ILLINOIS POWER COMPANY



Existing and Anticipated Future Delivery Points

Existing Delivery Points	Location	Supply Voltage
Brighton	SE¼, SW¼, Sec. 5, T7N, R9W, 3rd P.M., Macoupin County	34.5 kv
Bunker Hill	NW¼, NE¼, Sec. 12, T7N, R8W, 3rd P.M., Macoupin County	34.5 kv
Butler	NW¼, NW¼, Sec. 7, T8N, R4W, 3rd P.M., Montgomery County	34.5 kv
Rinaker	SW¼, SW¼, Sec. 33, T10N, R7W, 3rd P.M., Macoupin County	34.5 kv
Staunton	NW¼, NW¼, Sec. 22, T7N, R6W, 3rd P.M., Macoupin County	34.5 kv
Taylor Springs	SW¼, SW¼, Sec. 25, T8N, R4W, 3rd P.M., Montgomery County	34.5 kv
Witt	SW¼, SW¼, Sec. 10, T8N, R2W, 3rd P.M., Montgomery County	34.5 kv
Womac	NW¼, NE¼, Sec. 32, T10N, R6W, 3rd P.M., Macoupin County	34.5 kv
Harvel	NE¼, NE¼, Sec. 2, T10N, R4W, 3rd P.M., Montgomery County	34.5 kv
Honey Bend	NW¼, SW¼, Sec. 4, T9N, R5W, 3rd P.M., Montgomery County	34.5 kv
Lomax	SE¼, Sec. 6, T8N, R5W, 4th P.M., Henderson County	69 kv
Knoxville	NW¼, Sec. 29, T11N, R2E, 3rd P.M., Knox County	69 kv

Existing Delivery Points	Location	Supply Voltage
MJM Hdqtrs Building	262-268 N East St. Carlinville,	12 kv
WIPCO Hdqtrs Building	SE¼, NE¼, Sec. 32 T15N, R10W, 3rd P.M., Morgan County	12 kv

Anticipated Future Delivery Points	Location	Supply Voltage

SHORT TERM ENERGY TRANSMISSION AGREEMENT

THIS AGREEMENT was made on the _____ day of _________, 19__ between the Illinois Power Company (hereinafter called the "Company") and the electric utility systems of the municipalities of Breese, Carlyle, Farmer City, Freeburg, Highland, Mascoutah, Princeton, Peru, and Waterloo, Illinois (hereinafter each called a "Municipal Utility" and collectively called "Municipal Utilities.").

W I T N E S S E T H:

WHEREAS, each of the Municipal Utilities owns and operates certain electric generating facilities; and

WHEREAS, the Municipal Utilities desire to transmit energy to and from any other utility with an interconnection agreement with the Company; and

WHEREAS, the Municipal Utilities are interconnected with the Company's facilities; and

WHEREAS, the Company is willing to provide short term energy transmission service between the Municipal Utilities and any utility with an interconnection agreement with the Company (hereinafter called "Utility") under the terms and conditions contained herein.

NOW, THEREFORE, for and in consideration of the mutual promises hereinafter contained, the Municipal Utilities and the Company agree as follows:

1. The purpose of this Agreement is to provide for the transmission by the Company of electric energy between the Municipal Utilities and with any other utility which has an interconnection agreement with the Company on a short term basis under the terms and conditions set forth herein.

2. This Agreement shall become effective as of the date executed subject to any necessary regulatory approval and shall continue in force for a term of five years. The Agreement shall continue thereafter from year to year unless cancelled by either party at the expiration of the primary or extended term upon not less than two years prior written notice.

3. The Municipal Utility desiring to supply short term energy service shall notify the Company 24 hours in advance, or less if agreed to by Company's dispatchers, of the time of commencement of short term energy service, specifying the quantity and planned duration of short term energy requested to be transmitted. The Municipal Utility supplying such service shall notify the Company of the time of actual commencement and termination of short term energy service. In each case, the notice may be initially given by telephone to the Company's designated dispatcher but shall be subsequently confirmed in writing.

The Company shall bill the receiving Municipal Utility in accordance with notifications received from the supplying Municipal Utility, subject only to verification by the Company of actual operating conditions, and the receiving Utility shall, in all cases, be bound by notices sent to the Company by the supplying Municipal Utility. In cases where the receiving utility is not a party to this Agreement, the supplying Municipal Utility shall be billed by the Company.

Any scheduled transfers of short term energy shall not affect in any manner the computation of billings to Municipal Utilities for services rendered to them by the Company under other agreements.

4. For any energy transaction that occurs which involves a utility not a party to this agreement, the Municipal Utility shall notify the Company at least 24 hours in advance, or less if agreed to by Company's dispatchers, of the time of commencement of short term energy service. In each case, the notice may be initially given by telephone to the Company's designated dispatcher but shall be subsequently confirmed in writing.

5. The Municipal Utility receiving short term energy transmission service shall compensate the Company in accordance with the following schedule:

(a) $100 for each billing period in which Company's transmission facilities are used, plus

(b) 0.4¢ for each kwh scheduled to be delivered by the supplying Municipal Utility under the provisions of this Agreement, except as provided in Paragraph 6.

6. The Municipal Utility which notified the Company that it was supplying short term energy to be transmitted hereunder shall, in fact, generate such electric energy during the specified hours at the specified level described in the notices provided to the Company.

If the supplying Municipal Utility fails to generate during the specified hours at the specified level, the receiving Municipal Utility shall either arrange for another source of generation to supply short term energy to be transmitted hereunder or pay for any energy supplied by the Company in accordance with the "Wholesale Electric Service Agreement."

7. Insofar as it is practical, the supplying and receiving Municipal Utilities shall operate their systems so as to generate and absorb substantially all of the reactive kilovoltamperes (kilovars) required by their own systems and to maintain satisfactory voltage levels. The purpose of this provision is to permit sufficient latitude to the dispatchers when dispatching kilovars to obtain the most satisfactory joint system operation without working any undue hardship on any party by reason of the generation or absorption of a disproportionate amount of kilovars.

8. Nothing contained herein shall be construed as affecting in any way the right of either party under this agreement to unilaterally make application to the Federal Energy Regulatory Commission or any successor agency for a change in rates, terms or conditions under Section 205, or any similar provision, of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder or under any other applicable federal law or commission.

9. Company shall have the right to refuse to schedule transmission service, to reduce scheduled transmission service, or to terminate any transmission between Municipal Utilities at any time the Company determines, in keeping with good utility practice, that such transmission overloads its facilities, jeopardizes service to its firm customers, or interferes with any firm or emergency transmission obligation of the Company. However, the Company will make a special effort to provide transmission service during emergency conditions on one or more of the Municipal Utilities systems. In the event any curtailment or termination of transmission service is necessary, the Company will initially notify by telephone and provide a written explanation to Municipal Utilities of any curtailed or terminated transmission service.

10. The Company undertakes no obligation to construct or modify any of its facilities to facilitate service pursuant to this Agreement. If the Municipal Utilities desire additional facilities or upgrading of existing facilities, the Company's costs of constructing such facilities will be borne by the Municipal Utilities.

11. Electric energy to be transmitted by the Company pursuant to this Agreement shall be delivered by the supplying utility at its boundary with the Company and shall be delivered at the boundary of the Company with the receiving utility. The Company shall have no obligation or responsibility for arrangements for transmission of any electric energy outside the boundaries of its system.

12. Service hereunder shall be subject to verification on the basis of meter readings at both the interconnection point and on supplying Municipal Utility's generation integrated over each clock-hour period, and meters shall be maintained and tested by the Company in accordance with good utility operating practice. Existing metering equipment shall be used so far as practicable, and any new or additional metering equipment shall be owned by the Company and leased to the Municipal Utility. For accounting purposes, segregation shall be made of electricity delivered hereunder from other scheduled transactions between the Company and any of the Municipal Utilities under other agreements.

13. Bills for short term energy transmission service shall be rendered monthly to the Municipal Utility which receives the short term energy service, except in cases where the receiving utility is not a Municipal Utility wherein the bill will be rendered to the supplying Municipal Utility. Bills will be rendered in appropriate detail and may be rendered on an estimated basis. Each such bill shall be adjusted for curtailed service or for any errors in

arithmetic, computation, estimating, or otherwise. All payments shown to be due on each such bill, subject to subsequent adjustment a heretofore provided, shall be due and payable not later than fifteen (15) days after such bill is rendered.

14. The Company shall add to all charges under this Agreement the amount of any tax or charge of any kind levied, assessed or charged by any municipal, state or federal government or authority becoming effective after June 15, 1981 measured by but not included in the purchase price paid or revenues received by Company on account of the service rendered under this Agreement.

15. The Company shall not be liable in tort or contract to any of the Municipal Utilities for any damages, direct or consequential, resulting from any failure to provide service hereunder at any time for all or any part of the electric power generated by any Municipal Utility, or from any interruption, change or deficiency in quantity or quality of service caused by any such failure, unless such failure is the result of willful default by the Company; provided that in the event of any such failure, the Company shall use diligence to remove the cause of disability and to resume such transmission as promptly as practicable.

Municipal Utility shall not be liable for and Company shall save harmless against any and all claims, damages, liability or expense, resulting from or occasioned by the presence, use or maintenance of any electrical conductor or other type of equipment owned or maintained by Company or Municipal Utility or by the escape of electric energy in or from any such conductor or equipment, provided that such claims, damages, liability or expense shall be caused by Company's negligence or misconduct. Company shall not be liable for and

Municipal Utility shall save Company harmless against any and all claims, damages, liability or expense resulting from or occasioned by the presence, use of maintenance of any electrical conductor or other type of equipment owned or maintained by Company or Municipal Utility, or by the escape of electric energy in or from any such conductor or equipment, provided that such claims, damages, liability or expense shall be caused by Municipal Utility's negligence or misconduct. Negligence or misconduct, as used herein, shall include, but not be limited to, failure to comply with all Illinois Commerce Commission General Orders applicable to the furnishing of electric service by electric utilities, all regulations of the United States Occupational Safety and Health Administration and the Structural Work Act of the State of Illinois, or failure to meet any standard of care derived from any of such orders, regulations or statute.

16. This Agreement and all rights, obligations, and performance of the parties hereunder, are subject to all applicable state and federal laws and to all duly promulgated orders and other duly authorized actions of any state or federal authority having jurisdiction.

17. This Agreement shall be binding upon and shall inure to the benefit of, and may be performed by, the successors and assigns of the parties, except that no assignment, pledge or other transfer of this Agreement by any party shall operate to release the assignor, pledgor, or transferor from any of its obligations under this Agreement unless consent to the release is given in writing by the other party, or, if the other party has heretofore assigned, by such other party's assignee, pledgee or transferee, or unless such transfer is incident to a merger or consolidation with, or transfer of all or substantially all of the assets of the transferor to, another person or business

entity which shall, as a part of such succession, assume all the obligations of the transferor under this Agreement.

IN WITNESS WHEREOF, the Company, acting by its duly authorized officer, and the Municipal Utilities, each acting herein by its duly authorized officials, have caused their respective names to be signed hereto and to duplicate Agreements of like tenor and date.

ILLINOIS POWER COMPANY

BY______________________

ATTEST:

____
Secretary

CITY OF BREESE

BY______________________

ATTEST:

____
City Clerk

CITY OF CARLYLE

BY______________________

ATTEST:

____
City Clerk

CITY OF FARMER CITY

BY______________________

ATTEST:

____
City Clerk

CITY OF FREEBURG

BY____________________________

ATTEST:

____
City Clerk

CITY OF HIGHLAND

BY____________________________

ATTEST:

____
City Clerk

CITY OF MASCOUTAH

BY____________________________

ATTEST:

____
City Clerk

CITY OF PRINCETON

BY____________________________

ATTEST:

____
City Clerk

CITY OF PERU

BY____________________________

ATTEST:

____
City Clerk

CITY OF WATERLOO

BY_______________________________

ATTEST:

____
City Clerk

PR2

ELECTRIC TRANSPORTATION SERVICE AGREEMENT

Agreement Dated ____________, 19__

Between Illinois Power Company, an Illinois corporation herein called "Utility" and ____, herein called "Customer".

Customer owns and operates an electric distribution facility and provides electric public utility service to customers located in and about the ____.

Customer desires to contract for electric transportation service, and Utility desires and is willing and able to provide Customer with electric transportation service on the terms and conditions hereinafter set forth.

In consideration of the mutual agreements herein contained, the parties agree as follows:

1. Utility agrees to provide such electric transportation service and Customer agrees to accept and pay for service rendered hereunder, all in accordance with the rates, charges, terms and conditions set forth in Utility's Transportation Service Schedule, a copy of which is attached hereto and made a part hereof, which shall be on file with the Federal Energy Regulatory Commission as part of Utility's schedule of rates for electric service.

2. Customer requires and Utility agrees to provide transportation capacity during the primary term (First Five Years) according to the following five year schedule, beginning with the commencement of this agreement under Article 10. This capacity will be the primary term "transportation capacity" governed by the provisions of Sections 7a and 7b of the Electric Transportation Service Schedule.

	Transportation Capacity
1st year	________ kva
2nd year	________ kva
3rd year	________ kva
4th year	________ kva
5th year	________ kva

3. Transportation demand and energy will be delivered by Utility to Customer at ______ kv.

4. The Customer's point(s) of delivery at which electric transportation demand and energy will be accepted shall be:
____
____
____

5. The point(s) at which Customer's electric transportation demand and energy shall be measured (metering point(s)) shall be:
____
____
____

6. Transportation demand and energy shall be delivered to Customer subject to the following metering, recording, telemetering and control requirements: ________________
____
____
____
____

7. The following additional or modified facilities and equipment, for which Utility shall be reimbursed, shall be required: ______________________________________
____
____
____

8. The following additional or modified facilities shall be installed, owned and maintained by the Customer: ________
____
____
____

9. Transportation demand and energy will be delivered to Utility from supplier(s) in accordance with the Customer's contract(s) with that supplier(s) as shown in Exhibit A.

10. This agreement shall be for a primary term of five (5) years beginning on __________________ and shall continue thereafter from year to year unless cancelled by either party at the expiration of the primary or extended term upon not less than two years prior written notice.

11. This agreement shall not prejudice any future agreement for transportation service.

12. All provisions of this agreement which are obligatory upon or shall be to the benefit of Utility shall be to the benefit of all successors or assigns of Utility.

13. All provisions of this agreement which are obligatory upon or shall be to the benefit of Customer shall be to the benefit of all successors or assigns of Customer.

ILLINOIS POWER COMPANY	(Customer)
By____________________	By____________________
Title____________________	Title____________________
Date____________________	Date____________________
Attest:	Attest:
____________________	____________________
As to Illinois Power Company (Secretary)	As to ____________________

JAC5

Exhibit A

ELECTRIC TRANSPORTATION SERVICE AGREEMENT
Transportation Power Supplier(s) to Utility

Supplier No. 1:

Name____

Location and Description of Delivery Point to Utility____________

Supplier No. 2:

Name____

Location and Description of Delivery Point to Utility____________

Supplier No. 3:

Name____

Location and Description of Delivery Point to Utility____________

ILLINOIS POWER COMPANY
WHOLESALE ELECTRIC SERVICE SCHEDULE

ELECTRIC TRANSPORTATION SERVICE SCHEDULE

1. Availability

Service under this rate schedule is available subject to the following conditions:

(a) Customer is engaged in the distribution and sale of electricity to the general public.

(b) Customer's facilities will be interconnected with Illinois Power Company's (hereafter called "Utility") facilities,

(c) any party desiring electric transportation service from Utility shall make written application therefor and shall furnish such information with respect to the requested service as Utility may reasonably require.

(d) Customer desires to transport demand and energy from a supply source other than Utility, that will be interconnected with Utility's transmission facilities, and

(e) prior to the commencement of service, Customer shall enter into a written agreement with Utility for a primary term of five (5) years.

2. Conditions of Service

(a) Customer requires and Utility agrees to supply a maximum amount of transportation capacity according to a transportation capacity schedule agreed to between Utility and Customer. This capacity will be the primary term "transportation capacity" used herein. At the expiration of the primary term, Customer will specify a new transportation capacity for each subsequent two year period. In the absence of such specification, the transportation capacity specified for the previous year shall carry over to become the transportation capacity for the subsequent year.

(b) Service hereunder will be provided to Customer from three-phase electric lines having nominal standard voltages of 7,200, 12,470, 34,500, 69,000 or 138,000 volts and having capacity sufficient to handle the Customer's transportation power requirements. Utility retains discretion to select the supply line or lines from which service will be rendered to Customer. Utility also retains discretion to change such supply line or lines and to change the voltage of the supply lines. Should any change in service connection become necessary by reason of changes in service conditions or facilities initiated by Utility, the changes in costs of providing service under the new conditions shall be borne by Utility. In all other cases, costs of changes in service connections shall be borne by Customer.

(c) Utility shall have the right to reduce or terminate transportation service at any time Utility determines, in keeping with sound operating practice, that emergency conditions exist and such curtailment, reduction or termination shall be in accordance with the Federal Energy Regulatory Commission requirements.

(d) Customer shall be responsible for contracting with party(s), hereafter called "supplier", that will deliver transportation power to Utility's transmission system. Utility shall be responsible for coordinating joint system operation with the supply source to insure the integrity of the inter-connected system.

(e) Customer shall be responsible for the cost of facilities, determined by Utility, as necessary to permit interconnected operations with Utility. Utility may require an automatic circuit breaker at supply source(s) interconnection to protect Utility's system from a fault on supplier's system and to isolate the supplier's generation during a fault on Utility's system. Customer shall arrange and pay for the installation of a circuit breaker satisfactory to Utility. Utility shall control, operate, and maintain at Customer's expense such circuit breaker to assure satisfactory operation with its electric system.

(f) Utility undertakes no obligation to construct or modify any of its facilities to provide service pursuant to this Agreement. If the transportation service requires additional facilities or an upgrading of existing facilities, Utility's costs of constructing or upgrading such facilities will be borne by the Customer.

(g) Customer shall arrange for supplier to provide and maintain three-phase voltage interconnection(s) where power for transportation is delivered to Utility's system. Design and construction of Supplier's facilities shall be subject to Utility's approval. Customer will bear the costs of these facilities.

(h) Electric power transported by Utility shall be delivered to Utility at supply source(s) interconnection(s) and shall be received by Customer at its designated point(s) of delivery.

ILLINOIS POWER COMPANY
WHOLESALE ELECTRIC SERVICE SCHEDULE

ELECTRIC TRANSPORTATION SERVICE SCHEDULE - PAGE 2

2. Conditions of Service (continued)

(i) Utility shall have no obligation or responsibility for transportation of electric power other than through the above stated points of delivery.

(j) Service hereunder shall be subject to verification on the basis of meter readings at Customer's delivery point(s) integrated over each clock-hour period. Meters shall be maintained and tested by Utility in accordance with Utility's operating practice. Existing metering equipment shall be used in so far as practicable, and any new or additional metering equipment shall be owned by Utility and leased to the Customer. Customer shall make a non-refundable contribution to Utility for the salvable and non-salvable cost of any new or additional metering equipment plus a monthly maintenance fee for the meter so long as such charges are not previously provided for in another existing agreement between Utility and Customer.

(k) Utility and Customer may mutually agree to have telemetering facilities for monitoring instantaneous demands and operating in conjunction with Utility's Load Dispatch Center for the purpose of monitoring and control of system load. Utility shall own, install and maintain such telemetering facilities mutually agreed to by Utility and Customer. Customer shall be responsible for the cost of installation, operation and maintenance of such facilities.

If telemetering facilities have not been mutually agreed upon, the Customer shall submit to Utility's Load Dispatch Center on Friday of each week, an estimate of the total number of kilowatts of demand listed on an hourly basis, to be transmitted over the Utility's transmission system for each day of the following calendar week. A reconciliation procedure to account for the deviation, if any, between the estimated demands required and the actual demands incurred shall be included as part of the operating agreement required in Section 2(c) of this rate schedule.

(l) Where Customer is responsible for costs of facilities required by Utility, Customer shall make arrangements with Utility for total costs in advance of any construction.

(m) If Customer is a municipality, any towers, poles, wires or equipment placed by Utility on the streets, avenues, alleys and public places in the City for purposes of carrying out this agreement shall be exempt from any special tax assessments, license or rental fee to Utility.

(n) Representatives of Utility shall be permitted access to the premises of Customer to carry out the provisions of this rate schedule. Utility and Customer shall each have access to the facilities of the other at a mutually agreed upon time for the purpose of removing facilities where such removal is permitted or required under this rate schedule.

(o) Customer agrees to use reasonable care to design and maintain its circuits so that loads of the individual phases on its lines at the point of delivery will be balanced as nearly as practicable.

(p) Customer and Utility agree to maintain and operate their systems in accordance with sound utility practices, so as to minimize the likelihood of a disturbance in either system which might cause impairment of service to the other party's system.

(q) Customer shall provide supplier(s) resume(s) as required in Exhibit A contained herein.

3. Rates and Charges

(a) Customer shall pay Utility monthly for electric transportation service rendered at the charges due and payable in accordance with the following schedule:

Demand Charge

Delivery Voltage at Customer	Monthly Charge per Kva of Transportation Capacity
7,200 and 12,470 volts	$3.50
34,500 and 69,000 volts	$1.50
138,000 volts	$0.85

ILLINOIS POWER COMPANY
WHOLESALE ELECTRIC SERVICE SCHEDULE

ELECTRIC TRANSPORTATION SERVICE SCHEDULE – PAGE 3

3. Rates and Charges (continued)

(b) Other Charges

Utility shall add to all charges under this rate schedule the amount of any tax or charge of any kind levied, assessed, or charged by any municipal, state or federal government, or authority measured by but not included in the purchase price paid or revenues received by Utility on account of the service rendered under the rate schedule. Any application of this clause will constitute a change in rates which will require timely filing under Section 35.13 of the Regulations of the Federal Energy Regulatory Commission.

4. Meter Reading and Billing

(a) Utility shall read meters and render bills monthly. Bills will be rendered using the rates and charges contained in Section 3 in effect at the time, including other charges in this rate schedule. Payment shall be due thirty days from the date of rendering the bill. Accounts not paid in full within 30 days will be subject to an additional charge of 1 1/2% monthly on unpaid balance.

(b) Bills will be rendered in appropriate detail and, when necessary, may be rendered on an estimated basis. A bill shall be adjusted for curtailed service or for any errors in arithmetic, computation, estimating, or otherwise.

(c) For accounting and billing purposes, transportation service demand and energy delivered hereunder shall be segregated from power delivered from other schedules under other agreements between the Utility, Customer and supplier(s). When Utility delivers demand and energy to Customer, simultaneously and through a common metering point, under the Electric Transportation Service Agreement and under other agreements with the Customer, electric transportation service demand and energy shall be determined to be the current monthly transportation capacity as provided for in Section 7(a). Demand and energy delivered under the other agreements will be the total demand and energy measured less the transportation service demand and energy.

(d) If Customer has failed to pay any bill accruing under this rate schedule within thirty days after date of billing, Utility may discontinue transportation service provided at least fifteen days prior written notice has been given to Customer. Utility will not be liable in any manner for any loss or damage arising from such discontinuance of transportation service.

5. Metering, Testing and Billing Adjustments

(a) Utility shall own and maintain the meters and related metering equipment necessary to measure the demand and energy delivered to Customer by Utility at the point(s) of delivery. Metering equipment generally shall be located on the high voltage side of transformation in the event transformation shall be required by Customer. Utility at its discretion may elect to install such metering equipment on the low voltage side of transformation (whether or not for the convenience of Customer) and in such case both the demand and energy consumption will be increased to compensate Utility for transformer losses as measured by compensated metering equipment, or in the absence of such measurement, by computing such losses based on the manufacturer's data pertaining to the specific transformers installed.

(b) Utility may require metering on supplier's generation. Customer shall be responsible for the cost of the meter and related metering equipment. Utility shall own and maintain these metering facilities.

(c) Utility shall test and calibrate the meters by comparison with accurate standards at approximately twelve month intervals.

(d) Utility shall make special meter tests at the request of Customer. If a special test made at Customer's request shall disclose that meters are registering within 2 percent of 100 percent accuracy, Customer shall bear the expense of the test; otherwise, the cost of such test shall be borne by Utility. Utility shall give Customer three days advance notice of its intention to test and calibrate meters when requested in writing by Customer and Customer shall be permitted to witness any meter tests made by Utility.

(e) Meters found by test to be registering inaccurately shall be restored to a condition of accuracy. If the inaccuracy exceeds 2 percent, the meter readings taken during the period of 90 days preceding (or during such shorter period as may have intervened since the previous test) shall be corrected by the percentage of inaccuracy found by the test and payment adjusted accordingly. No prior readings will be corrected.

ILLINOIS POWER COMPANY
WHOLESALE ELECTRIC SERVICE SCHEDULE

6. Continuity of Service and Liability

(a) If Utility must curtail load due to an uncontrollable event on its system, Electric Transportation Service shall have the same priority of service as other firm load.

(b) The obligation of Utility to transport demand and energy to the Customer shall be limited to times during which demand and energy is actually received from the supplier(s) by Utility for delivery to the Customer.

(c) Service under this schedule may be discontinued in accordance with the terms and provisions set forth herein.

(d) Utility shall provide adequate and reliable service to Customer. However, Utility shall not be liable to Customer for interruption or inadequacy of service, loss or damage to property, or injury (including death) to any person caused by act of God, public enemy, vandalism, strikes and other labor troubles or their equivalent, legal process, state, municipal or other governmental regulation, windstorm, flood, fire or explosion, or other matter of thing beyond Utility's control, whether the same shall affect or occur in connection with the operations or property of Customer, Utility or any other person.

(e) Utility shall not be responsible in damages for any failure to supply electricity, or for interruption; or reversal of the supply, if such failure, interruption, or reversal is without willful default or gross negligence on its part, nor for interruptions, by underfrequency relays or otherwise, to preserve the integrity of Utility's system or interconnected systems.

(f) Utility may interrupt service to make necessary repairs or to make changes in equipment or to install new equipment, but only for such reasonable times as may be unavoidable. If the nature of the situation permits, reasonable advance notice of these interruptions shall be given by Utility.

(g) Customer shall not be liable for and Utility shall save Customer harmless against any and all claims, damages, liability or expense, resulting from or occasioned by the presence, use or maintenance of any electrical conductor or other type of equipment owned or maintained by Utility or Customer or by the escape of electric energy in or from any such conductor or equipment, provided that such claims, damages, liability or expense shall be caused by Utility's negligence or misconduct. Utility shall not be liable for and Customer shall save Utility harmless against any and all claims, damages, liability or expense resulting from or occasioned by the presence, use or maintenance of any electrical conductor or other type of equipment owned or maintained by Utility or Customer, or by the escape of electric energy in or from any such conductor or equipment, provided that such claims, damages, liability or expense shall be caused by Customer's negligence or misconduct. Negligence or misconduct, as used herein, shall include but not be limited to failure to comply with Illinois Commerce Commission General Order No. 160 applicable to the furnishing of electric service by Utility or Customer, all regulations of the United States Occupational Safety and Health Administration and the Structural Work Act of the State of Illinois, or failure to meet any standard of care derived from any of such orders, regulations or statute.

7. Additional Conditions and Provisions

(a) Transportation Capacity is the maximum amount of power that is to be contracted for in accordance with the Electric Transportation Service Agreement. In the event supplier(s) deliver demand and energy to Utility in excess of the Transportation Capacity, the Transportation Capacity shall automatically be increased, without notice or other action, to the amount of maximum demand and energy measured during any clock-hour period.

(b) Customer may reduce Customer's transportation capacity upon providing Utility with twelve months' prior written notice. However, in no event shall Customer be permitted to reduce Customer's transportation capacity to a level below that specified under Section 2 of the Electric Transportation Service Agreement or Section 2(a) of the Electric Transportation Service Schedule.

(c) Utility and Customer shall enter into an operating agreement which will include, but not be limited to, scheduling for transportation demand and energy transactions, notification to parties to a transaction, billing for demand and energy transported, and the reconciliation of any deviation between the estimated demand required and the actual demand incurred provided in Section 2(k) of this rate schedule.

ILLINOIS POWER COMPANY
WHOLESALE ELECTRIC SERVICE SCHEDULE

7. **Additional Conditions and Provisions (continued)**

(d) Utility will deliver an amount of energy less than that which is delivered to Utility by supplier(s) to account for losses incurred on Utility's system. The amount of energy delivered will be reduced by the following factor:

For service occurring between Customer and Utility:	Factor
7,200 and 12,470 volts	.08
34,500 and 69,000 volts	.04
138,000 volts	.03

(e) Demand and energy furnished to Customer by Utility and not provided by supplier(s) shall be provided in accordance with provisions of other agreement(s) with Customer. In the event that Customer is not taking service under one of Utility's wholesale agreements, Utility shall bill Customer in accordance with the applicable wholesale agreement.

(f) Insofar as it is practical, Customer shall operate its system so as to generate and absorb substantially all of the reactive power (kilovars) required by its system and to maintain satisfactory voltage levels. The purpose of this provision is to permit sufficient latitude to Utility's dispatchers when dispatching kilovars to obtain the most satisfactory joint system operation without working any undue hardship on any party by reason of the generation or absorption of a disproportionate amount of kilovars.

(g) Nothing contained herein shall be construed as affecting in any way the right of either party under this rate schedule to unilaterally make application to the Federal Energy Regulatory Commission or any successor agency for a change in rates, terms or conditions under Section 205, or any similar provision, of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder or under any other applicable federal law or commission. It is further provided, however, that in the absence of agreement by Customer no change shall be made in any term or condition or service specified in this Wholesale Electric Service Schedule until it has been finally approved by the Federal Energy Regulatory Commission or any successor agency under Section 206 of the Federal Power Act.

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STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

ILLINOIS POWER COMPANY	:	
Proposed general increase in electric rates.	:	80-0544 and 80-0365
ILLINOIS COMMERCE COMMISSION On its own motion	:	
Implementation of the Public Utility Regulatory Policies Act for the Illinois Power Company.	:	

O R D E R

By the Commission:

On August 8, 1980, Illinois Power Company ("Company," "Respondent" or "Illinois Power") filed tariff sheets in which it proposed general increases in its electric rates effective September 8, 1980.

Notice of the proposed general rate increase was posted in a conspicuous place in each of Respondent's business offices and published in newspapers of general circulation throughout Respondent's service area pursuant to the requirements of Section 36 of the Illinois Public Utilities Act and the provisions of General Order 157, Revised, of the Commission.

An examination of the filed tariff sheets resulted in a determination by the Commission that hearings should be held concerning the propriety and reasonableness of the proposed general increases and that, pending hearing and decision thereon, the filed tariff sheets should not become effective. Therefore, on August 20, 1980, the Commission entered an Order suspending the effective date of the filed tariff sheets to and including January 5, 1981, and on December 30, 1980, the Commission resuspended the effective date of the filed tariff sheets to and including July 5, 1981.

Petitions to Intervene were filed on behalf of Central Illinois Consumer Energy Council ("CICEC"); Prairie Alliance; Illinois Association of Community Action Agencies on behalf of Western Egyptian Economic Opportunity Council, BCMW Community Service, Illinois Valley Economic Development Corporation, and Vermilion County Community Action Agency; Department of Defense; Granite City Steel Division of National Steel Corporation, Olin Corporation, American Steel Foundries, a Division of Amsted Industries, Jones & Laughlin Steel Corporation, Excelsior Foundry Company, General Motors Corporation, General Tire and Rubber Company, Firestone Tire and Rubber Company, and Borg-Warner Chemicals, Division of Borg-Warner Corporation ("Industrial Power Users"); People Against Inflation Now; Grain and Feed Association of Illinois; Illinois Public Interest Research Group ("IPIRG"); Organizing Committee for Eastern Madison County; Illinois Office of Consumer Services ("OCS"); National Town Meeting at Edwardsville; and Bradley Park - Mt. Olive Manor Concerned Tenants Organization, Counseling and Complaints, Inc. ("Bradley Park").

In addition the following municipalities filed Petitions to Intervene or became formal intervenors by causing to be filed the written appearance of their attorneys: Town of Normal, Village of Buffalo, City of Bloomington and City of Kewanee.

All persons and entities hereinbefore listed were granted intervention by order of this Commission and allowed full opportunity to participate in these proceedings. Respondent objected to the Intervening Petition of OCS and on December 11, 1980 filed an Application for Rehearing and Reconsideration of the Commission's Order granting the Petition to Intervene of OCS, which Application was denied by the Commission on December 23, 1980.

Pursuant to notice as required by law and by the rules and regulations of this Commission, the initial hearing in this cause was held before a duly authorized Hearing Examiner of the Commission at its offices in Springfield, Illinois on September 18, 1980. Subsequent to the initial hearing date 33 hearings were held at the offices of the Commission on the days shown by the docket sheets maintained by the Chief Clerk of this Commission for purposes of this cause and as a part of the record in this case. Additional hearings were held in the Illinois municipalites of Bloomington, Urbana, Decatur, Danville, Edwardsville and Kewanee, at which times public statements were made by and on behalf of certain persons and entities having an interest in the subject matter of this proceeding.

On June 4, 1980, the Commission entered an Order initiating a proceeding docketed as 80-0365, to consider, as required by the Public Utility Regulatory Policies Act ("PURPA"), the ratemaking standards of Section 111 of PURPA as they relate to Respondent. Notice of the institution of the PURPA proceeding was sent to Respondent, to all parties allowed to intervene in Respondent's last general rate proceeding, and to all parties required by the Illinois Public Utilities Act and the rules and regulations of the Commission to be notified of a general rate proceeding. A notice was also published in 3 newspapers of general circulation in Respondent's service area and the official state newspaper.

Petitions to Intervene in the PURPA proceeding were filed on behalf of OCS; Helen Williams; Department of Defense; General Motors Corporation; Granite City Steel, Division of National Steel Corporation; Excelsior Foundry Corporation; Jones & Laughlin Steel Corporation; Olin Corporation; Borg-Warner Chemicals, Division of Borg-Warner Corporation; American Steel Foundries, a Division of Amsted Industries; General Tire & Rubber Company; Firestone Tire & Rubber Company; Bradley Park and CICEC. All persons and entities hereinbefore listed were granted intervention by Order of this Commission and allowed full opportunity to participate in the PURPA docket.

Pursuant to notice as required by law and by the rules and regulations of this Commission, the initial hearing in the PURPA proceeding was held on July 8, 1980 before a duly authorized Hearing Examiner of the Commission at its offices in Springfield, Illinois. Subsequent to the initial hearing, 5 additional hearings were held at the offices of the Commission. Testimony and exhibits relevant to the subject matter of the PURPA docket were filed in Docket No. 80-0544 as well as the PURPA docket and cross-examination of such evidence conducted on the record of Docket No. 80-0544.

At the hearing held on April 7, 1981, the Hearing Examiner consolidated Docket No. 80-0365 for briefing and decision with Docket No. 80-0544. The parties have filed briefs addressing the subject matter of both dockets and the Commission has fully considered the consolidated record.

On April 9, 1981, at the conclusion of full and public hearings, the consolidated record of dockets 80-0544 and 80-0365 was marked "Heard and Taken." Oral Argument was

heard by the Commission on June 9, 1981, at which time the matter was marked "Heard and Taken Under Advisement."

The consolidated record contains in excess of 4,800 pages of transcript and numerous pages of prepared written testimony and statistical and other exhibits. The record provides, inter alia, a detailed analysis of the financial affairs of the Company, its operating revenues and expenses, the original cost and trended original cost and associated accrued depreciation of the Company's property, the cost of capital and other matters relating to the rate of return.

NATURE OF RESPONDENT'S OPERATIONS

Illinois Power Company furnishes electric service within areas of Illinois comprising approximately 15,000 square miles. At December 31, 1979, the Company furnished electric service to approximately 516,858 electric customers in 429 communities, in areas having a population of approximately 1,370,000. The largest cities in which electric service is provided are Monmouth, Galesburg, Kewanee, La Salle, and Ottawa in north central Illinois; Bloomington, Normal, Jacksonville, Decatur, Champaign, Urbana, and Danville in central Illinois; and Wood River, Granite City, Collinsville, Belleville, Centralia, and Mt. Vernon in southwest Illinois.

The Company's electric generating facilities have a net summer capability of about 3,815 MW, with about 3,626 MW in five conventional steam generating plants and the rest in other generating facilities including internal combustion and hydro units. Respondent is currently constructing a sixth generating station near Clinton, Illinois, which will have a capability of 950 MW. Respondent will own 760 MW of this unit and two wholesale electric cooperatives will own the remaining 190 MW. Respondent also has about 55 MW of capacity available under contract with Electric Energy, Inc., and maintains interconnections with major neighboring utilities.

PROPOSED CHANGES IN ELECTRIC RATE SCHEDULES

Respondent proposes a general increase in its charges for retail electric service. The proposed electric rate increase, exclusive of additional charges for revenue taxes under Riders A and AA, is approximately $126.7 million, or 24.4%, based on consumption for the calendar year 1980. Under a staff proposed alternative method of computing revenues in connection with the Uniform Fuel Adjustment Clause, fuel adjustment revenues would be lowered by $1,933,000 resulting in an overall increase of $124,767,000.

The proposed increases in charges for electric service include general increases for all retail service classifications. The proposed increase for the residential-small use class is 27.3%, for the residential-general class is 24.8%, for the general service class is 23.1%, for the industrial customer class is 24.7%, for the municipal class is 30.2%, and for the lighting class is 17.9%. Respondent's Manager of Rates testified that the proposed revenue requirements and revenue increase by class were based on an analysis of cost of service study results which showed the municipal and residential customer classes to have substantially lower rates of return then the general service and industrial classes.

Rate Design Principles and Cost of Service Information

Respondent presented in evidence a summary of embedded and marginal cost data which it used in designing its proposed rates. An embedded cost of service study based on

1979 book data adjusted to reflect year-end rate and tax levels was presented. This study showed the rate of return by customer class. Marginal cost data which Respondent used to set specific rate elements was also presented.

A witness on behalf of Respondent presented data on marginal energy costs by rating period and by functional level of service; long-run marginal capacity cost, based on the marginal capacity cost of serving an additional increment of load coincident with system peak; and incremental customer costs. Respondent's witness testified that Respondent's proposed basic energy charge for each class of service was determined based on marginal energy costs with an adjustment of approximately 10% to reflect the Company's opportunity costs of foregone interchange transactions; and that proposed demand charges were designed based on the long run marginal cost of capacity.

Respondent's witnesses testified that additional criteria were utilized in designing the proposed rates. These criteria included value of service, customer impact and understanding, revenue stability, effectiveness in yielding total revenue requirements, historical continuity of rate design and avoidance of disproportionately large increases for individual customers.

Witnesses testifying on behalf of Bradley Park and on behalf of Industrial Power Users also presented, respectively, marginal cost and embedded cost analyses. These witnesses' presentations were based on marginal and embedded cost data furnished by Illinois Power Company.

The witnesses testifying on behalf of Bradley Park recommended that Respondent's rates be set equal to marginal cost. The witnesses' recommendation that electricity rates should be set at marginal cost was based on welfare economics. According to economic theory, social welfare is maximized when price is equal to marginal cost. The witnesses' analysis and recommendations were based on the standard of economic efficiency and on the theory that the goal of rate regulation should be to achieve the most efficient allocation of resources.

The Bradley Park witnesses testified that electricity rate regulation that promotes economic efficiency is desirable because it helps ensure that those goods and services valued most by society are being produced from the limited resources available. The witnesses stated that rates based on marginal costs (which measure the change in total cost resulting from an additional unit of output) are the only costs that are truly causal and avoidable and thus they (and not embedded or average costs) reflect the resources that can be saved if the good, in this case electricity, is not consumed.

According to the Bradley Park witnesses, the closer rates come to being based on marginal costs, the better price signals customers receive about the true cost of the resources that will be used in producing the marginal unit of electricity. Given accurate price signals, the customers will be able to judge the consequences of their consumption and energy resources will be allocated most efficiently. In addition to promoting economic efficiency and conservation, these witnesses indicated that marginal cost-based rates promote equity by more accurately charging customers for the costs of the electricity they consume.

The Bradley Park witnesses did not evaluate other considerations such as value of service, undue discrimination, customer acceptability, rate continuity, earnings stability, or customer comprehensibility and responsiveness but acknowledged that these are appropriate considerations for the Commission to take into account in the overall ratemaking process.

Three witnesses testifying on behalf of the Industrial Power Users offered evidence in opposition to the principle of basing electricity rates on marginal cost. The position taken by these witnesses was that rates should be based on the actual embedded costs used by the Commission to determine the utility's revenue requirements. The witnesses identified numerous problems associated with the use of marginal cost in setting utility rates including the following:

1. Marginal costs are not used to establish the revenue requirement of the utility, and should therefore not be used to determine the cost to serve customer classes.

2. There is no supportable or rational way of matching the so-called "marginal" costs for customer classes to the actual costs (revenue requirements) for the utility.

3. Even if it were possible to precisely calculate and utilize elasticities of demand among customer classes to adjust to marginal costs, such an approach would be highly inequitable for it would imply that two different customers who have both the same embedded cost and the same marginal cost would have to be charged different rates.

4. There are numerous definitions and concepts of marginal costs, and no general agreement as to calculating them.

5. The marginal cost of the theory is the "marginal social cost," as opposed to the "private marginal costs," but there is no method for calculating marginal social costs.

6. Even if marginal social costs could be accurately specified, there is no reason to believe that pricing electricity at marginal cost would produce any better allocation of resources than would pricing of electricity at embedded costs.

7. Regulation is designed to permit a utility to recover its total costs (including its marginal cost associated with the last unit of output), and is specifically not designed to permit a utility to recover its "marginal" costs from all of its sales.

8. Marginal cost rates are inherently unstable since they violate the fixed costs/variable costs distinction which

is fundamental to providing proper price signals and tracking costs.

The Industrial Power Users' witnesses also testified that many methods for implementing marginal cost based rates can result in unfair, non-cost-justified burdens being placed on larger industrial customers which may lead these customers to reduce operations in, or to leave, a particular utility's service area, to the detriment of the economy of the area and of the remaining customers who must bear a larger portion of the utility's fixed costs. The Industrial Power Users' witnesses relied heavily on the report of the Ontario Energy Board on Principles of Electricity Pricing for Ontario Hydro, dated December 20, 1979, which concluded, after extensive hearings, that economic efficiency is not a proper basis for electricity pricing, that marginal cost pricing should be rejected for rate design purposes, that marginal cost-based electricity rates should be rejected, and that accounting costs, adjusted to a future test period, should be used for rate design purposes.

The Commission has fully reviewed all the evidence submitted by the parties hereto on the appropriateness of using marginal cost or embedded cost as the basis for rate design, including the specific rate applications of each approach which are discussed in greater detail elsewhere in this Order. The Commission is not in agreement with the position taken by the Industrial Power Users that problems raised by their witnesses in connection with the use of marginal cost as the basis for setting electric utility rates should bar the use of this data in the ratemaking process. The Commission finds its position with regard to these problems to be consistent with that expressed by the New York Public Service Commission in its Opinion No. 76-15 in the New York Generic Rate Design Case, No. 26806:

> "These are the principal arguments advanced in support of the proposition that marginal costs have no proper role in electric rate structures. They do not in our judgment overcome the compelling affirmative presentation by the marginalists. We conclude, therefore, that marginal costs do provide a reasonable basis for electric rate structures. This finding does not mean that rate structures must in <u>all</u> cases embody marginal cost pricing or that rate structure in <u>any</u> case should be based exclusively on such principles, but it does mean that marginal costs are an important tool for consideration in all rate cases and that failure to take these principles into account should be justified."

Although the Commission is of the opinion that economic efficiency should be the principle criterion for electric rate design, the Commission is cognizant of the importance of other considerations raised by the Industrial Power Users' witness such as customer impact, customer understanding and acceptance, continuity of rates, earnings stability and value of service, and will proceed with caution.

The Commission stated in its recent Order in <u>Union Electric Co.</u>, Docket Nos. 80-0370 and 80-0368 Consolidated (April 15, 1981), that marginal cost methodologies are appropriate for the pricing of electricity both within and among classes of service because such pricing "promotes the efficient use of the Company's resources in producing electricity and leads to equitable and reasonable rates for all customers."

The Commission is of the opinion that the marginal cost data presented by Respondent provide a proper basis for the design of electric rates and should be utilized for that purpose in this proceeding. The Commission is also of the opinion that the additional considerations relied on by Respondent in designing rates are relevant to the ratemaking process and should be considered along with cost of service information. As the Commission stated in the last Illinois Power rate order, Docket No. 79-0071, quoting from Central Illinois Public Service Company, Docket No. 76-0304 (1977) (pp. 5-6):

> "The Commission has previously observed the importance of cost-of-service studies in rate proceedings and has indicated in other rate cases, and continues to be of the opinion, that there are many factors, other than cost of service, which properly should be taken into account in setting rates. In Docket No. 58340, the Commission stated the following:
>
> > The determination of just and reasonable rates is admittedly not an exact science but embodies managerial discretion, innovative regulation, and general acceptance by the public and the customers served. Cost-of-service studies utilize the factual information of the past and cannot incorporate matters of public policy, social, industrial or political changes which will occur in the future. Cost analysis cannot establish the value of a utility service to a customer or a class of customers. Regardless of the method used, cost of service studies should be considered only as a guide.
>
> The Commission also reiterates that there are many acceptable methods of developing cost-of-service studies, no one of which can be said to be free of predisposition or arbitrariness or eliminates the need for judgment with respect to questions of public policy and economics."

The record reflects, as summarized above, that the various witnesses testifying in this proceeding offered widely varying opinions as to the type of cost data which should be used in designing electric rates and on the extent to which considerations other than the cost of service should be evaluated in designing rates. The record reflects that specific demand and energy changes in Respondent's proposed tariffs are consistent with marginal cost while giving weight to other important considerations such as customer impact, the value of service, historical continuity of rate design and earnings stability.

Residential Service Classification

Respondent proposes increases in facilities charges and all rate blocks for Service Classifications ("S.C.") 1 and 2. It proposes to eliminate one of the three existing energy charge blocks in the winter season for S.C. 1 and 2, leaving a flat summer rate and a two-step winter rate. Respondent also proposes an increase in on-peak energy charges in S.C. 4, optional time-of-day service.

Respondent proposes a new S.C. 3, demand-metered time-of-day residential service applicable to customers using more than 150 kwh per day in any one of the four summer months. Respondent states that it is proposing this rate form for its largest residential customers because their energy consumption is high enough to indicate that the additional metering cost required to implement the rate form will be cost-effective, and because the demand-metered time of day rate form will more accurately reflect the costs of serving these customers. Respondent proposes that customers placed on S.C. 3 be required to stay on it so long as their consumption in any summer month is equal to or greater than 125 kwh per day. Respondent states that it expects to obtain experience in administering this rate which will be relevant to further implementation of time-of-day rates for residential customers.

Respondent proposes facilities charges of $5.00 per month for S.C. 1 and $8.50 for S.C. 2. Respondent presented a cost of service study which showed that the rates of return earned in 1979 based on present rates from the S.C. 1 and 2 customers were substantially less than the Company average and substantially less than that earned on sales to general service and industrial customers. Respondent's witness testified that the principal reason for the low rate of return for the residential classes is the fact that the residential facilities charge does not recover the full residential customer cost. He proposed increases in facilities charges in order to align residential rates more closely with the cost of service.

Respondent's witness presented data on embedded and incremental residential customer costs. The witness presented embedded customer costs calculated using the minimum distribution system approach which he testified was the prevalent method used in the industry. Under this approach, the cost is calculated on a minimum distribution system which the utility must have in place in order to stand ready to serve customers. The costs attributed to the customer component under this approach include a portion of the cost of distribution primary lines, secondary lines, line transformers and customer service drops as well as the full cost of meters, meter reading and billing and miscellaneous customer accounting expenses. Under this approach, Respondent showed a 1979 embedded customer cost of $7.37 per month. The witness also showed that the 1980 incremental cost of these facilities is $23.48 per month.

A Commission Staff witness disagreed with Respondent's identification of the facilities which are attributable to the customer component. The witness testified that the customer costs should be limited to the cost of the service drop, meters, meter reading and miscellaneous customer expense using the embedded cost data presented by Respondent. The witness testified that the cost of these items was $3.60 per month and recommended that the S.C. 1 facilities charge be set at that level. He further specified that in the event of rate level reduction, the customer charge for S. C. 1 should not fall below $3.00. He recommended a facilities charge for S.C. 2 of $5.10 per month in order to recover certain additional costs associated with serving S.C. 2 customers and to maintain a differential between the rates. He proposed to recover the revenue foregone by lowering the facilities charge by raising energy charges in the summer and the initial block in the winter from the level of 5.32¢ per kwh proposed by Respondent to 5.82¢ per kwh.

Two witnesses testifying on behalf of Bradley Park also disagreed with Respondent's calculation of customer costs.

These witnesses recommended that rates should be set based on marginal costs and that any revenue thereby produced in excess of the legal revenue requirements determined by the Commission should be reduced by lowering the customer charge to a minimum of $1.00 per month. Using their calculation of marginal cost-based revenues and based on the proposed full revenue requirements for the residential class, these witnesses calculated a customer charge of $2.11 per month.

Both Bradley Park witnesses testified that if the residential facilities charge were based on customer costs rather than used as a mechanism for reconciling marginal cost revenues with revenue requirements, it should be calculated based on the incremental cost of services, meters, meter reading and billing. The witnesses based their opinion on the theory that the facilities charge should recover only the additional costs which Respondent would have to incur to add a residential customer to its system, which they asserted was the cost of the service drop, meter and meter reading, billing and accounting expense. Respondent's evidence showed the incremental cost of these facilities to be in the range of $8.23-$10.30 per month.

Respondent contested the facilities charges proposed by the Staff and Intervenor witnesses and presented evidence which it stated showed that recovery of less than full customer costs through facilities charges results in subsidization of customers using small amounts of energy for non-domestic purposes by customers using larger amounts of energy for domestic purposes. Respondent's Manager of Rates presented the results of a study on the end uses of residential customers who receive monthly bills of 50 kwh or less. The study disclosed that approximately 90% of such bills are rendered to facilities such as vacant premises, barns, water pumps, garages, summer cabins or campers while less than 3% is rendered to premises using electricity for domestic purposes. The evidence showed that the bulk of these "low use" bills are rendered to customers using electricity mainly for convenience or who have second points of delivery on their premises because it is cheaper for the customer to pay a low facilities charge than to have his service extended to the second point of usage such as his garage.

Respondent also showed that the rate design proposed by the Staff witness, with a lower facilities charge and a higher energy charge, would benefit principally customers using small amounts of electricity, who, Respondent's evidence showed, do not use electricity for domestic purposes. Under the Staff witnesses' rate design, S.C. 1 customers consuming more than about 275 kwh per month in the summer would pay more per month than under the Company's proposed rate. However, when an analysis is performed on the entire range of users in each class, it appears from the record that the Staff proposed rates provided a more equitable increase to all customers.

The Commission has reviewed the customer cost data presented by Respondent's witnesses, Staff witnesses and other parties, and the testimony given in connection therewith. The evidence shows that the facilities charges proposed by Staff are more closely representative of the costs imposed directly on the Company by each customer. The so-called minimum distribution system, as analyzed by the Respondent's witness, overstates the costs of connecting each additional customer and is inappropriate for rate design purposes. In summary, the Commission finds the Staff proposed facilities charges to be consistent with the appropriate cost data, and are therefore reasonable and should be adopted. The facilities charges for S.C. 1 and S.C. 2 should be $3.00 and $5.10, respectively.

Respondent has proposed to commence implementation of mandatory time-of-day service for its largest residential customers and has proposed to continue optional time-of-day service available to all S.C. 2 customers. Witnesses testifying on behalf of Bradley Park testified that time-of-day rates should be implemented over a ten-year period for Respondent's largest S.C. 2 customers consuming the top 35% of class. The witnesses did not identify the number of customers involved or the cut-off point for implementation in terms of annual kwh usage per customer although it appears from information submitted by Respondent that approximately 124,000 residential customers would be involved.

The Bradley Park witnesses' recommendation was based on an analysis which compared the welfare benefits or gains which would accrue to society from equating electric rates to marginal cost to the additional metering costs which Respondent would have to incur to implement time-of-day rates. One of the witnesses testified that a different type of cost-benefit test, comparing reduced costs to the utility from shifts or reductions in load to additional metering or implementation costs, was economically inappropriate and should not be performed or used.

The Bradley Park witnesses testified that their proposal was based on considerations of economic efficiency in terms of maximizing the efficiency of allocation of resources resulting from electric rates and was not intended to reflect non-economic criteria. The witnesses presented various proposed rates, on both a time-of-day and non-time-of-day basis for the residential, commercial and industrial classes, designed to recover 100% of Respondent's proposed revenue requirements, 50% of the proposed revenue requirements and the current revenue requirements, based on 1979 usage. Steps or phases for moving from the current rates to the full marginal-cost based rates were also presented although no time period for reaching the final proposed rate was suggested. For the residential class, it was recommended that S.C. 1 be abolished and that charges to all residential class based on 1979 usage be stated as follows:

All summer kwh:	11.15¢ per kwh
All winter kwh:	2.34¢ per kwh
Customer charge:	$2.11 per month

Respondent objected to the rates and rate design proposed by the witnesses for Bradley Park on a number of grounds including:

(1) Their rate design failed to consider important ratemaking criteria such as customer impact and earnings stability;

(2) Their rate design failed to consider the importance of having individual charges, such as facilities charges, reflect corresponding costs;

(3) Their rate design did not reflect a proper computation of energy charges to reflect all appropriate costs and contained an excessive summer-winter differential, about 4.75:1, particularly since the difference between Respondent's summer and winter peaks is narrowing;

(4) The recommendation was based on a form of cost-benefit analysis which considered the costs and benefits to society as a whole while failing to consider the specific implementation costs, and benefits in terms of reduced revenue requirements, to Respondent and its ratepayers;

(5) The Bradley Park witnesses did not evaluate the impact that possible load shifts could have on Respondent's system reliability and costs; and

(6) the analysis of welfare gains vs. additional metering costs was prepared using data from other utilities which overstated the likely response of Illinois Power customers to the proposed rate design and understated the additional metering costs.

Respondent's witnesses presented various analyses to show that the Bradley Park witnesses' proposed rate design could result in wide swings in revenue and income during warmer or colder than normal weather, and that, while the rates proposed by the Bradley Park witnesses would recover about the same revenue in total as Respondent's proposed rates and would give some customers smaller annual rate increases than would be received under Respondent's proposed rates, many customers would receive disproportionately high monthly and annual bill increases under the rate design proposed by the Bradley Park witnesses.

Witnesses appearing on behalf of Industrial Power Users for reasons previously summarized herein opposed the design of rates based on principles of marginal cost. The position of the Industrial Power User's witnesses was that rates should be based on the same embedded cost data used by the Commission to determine revenue requirements for the utility. The witnesses presented embedded cost of service analyses showing that the rates of return earned by Respondent on sales to residential customers were substantially less than on sales to industrial customers, and that the average cost of service per kwh is much lower for industrial than for residential customers due to such factors as intensity of use, load factor and facilities used. Industrial Power Users recommended an allocation of the proposed revenue increse which would allocate a larger revenue increase to the residential class and a smaller increase to industrial customers.

The Commission is of the opinion, as stated previously in this Order, that the principles of rate design stated by the witness for Bradley Park should be a primary objective of rate regulation. The Commission is also of the opinion, he however, that caution should be exercised in the implementation of marginal cost based rates and that the specific rates and rate design proposed by witnesses for Bradley Park should not be adopted. The Commission is particularly concerned with the impact on a substantial number of individual customers who would receive large bill increases under the rate design proposed by the Bradley Park witnesses, and on the adverse implications of their rate design for earnings stability, particularly the extreme summer/winter differential which they have proposed.

The Commission accepts the time-of-day rate design proposed by Respondent and finds that such rates should be implemented no later than August 1, 1981. If at that time facilities are not available and installed at every customer's premise in order to measure demand, each such cus-

tomer should be billed according to the minimum contract capacity as specified by the rate.

The Commission further finds that Respondent should file a report, not later than 60 days following the date of this Order, addressing the feasibility of expanding Rate 4 to approximately the largest 5% of the residential class in order to implement a time-of-day rate for these customers for the summer season in 1982.

Based on all the evidence of record, and taking into account the aforesaid exceptions, the Commission finds the Staff proposed rates to be reasonable and should be adopted.

General Service Classifications

Respondent proposes increases in all charges for the general service rates, Service Classifications 10, 11 and 13. In addition, Respondent's witness testified that, due to the availability of more sophisticated metering capabilities, Respondent proposed certain modifications to the time-of-day metering option under S.C. 11 in order to provide a more precisely-defined on-peak period; and to eliminate the special meter reading option under S.C. 11, which elimination may encourage more commercial customers to take time-of-day service in order to limit the time period for measurement of demands to determine contract capacity. Respondent also proposed to eliminate the provision in S.C. 11 for determination of the transformation charge based on connected load. These proposals are all reasonable and should be adopted.

The witnesses testifying on behalf of Bradley Park recommended implementation of time-of-day rates over a five year period for general service customers consuming more than 33,000 kwh per year. The final rates proposed by these witnesses to recover 100% of the proposed revenue requirements were:

	S.C. 10	S.C. 11
All summer kwh:	12.48¢/kwh	9.06¢/kwh
All winter kwh:	2.39¢/kwh	2.08¢/kwh
Customer Charge:	$11.62/month	$65.76/month

The Commission is of the opinion that this recommendation should not be adopted at this time. However, the Commission further finds that Respondent should file a report, not later than 120 days following the date of this Order, addressing the feasibility of an explicit time-of-day rate for the largest Rate 11 customers.

Based on all the evidence the Commission is of the opinion and finds that the general service rates and rate design proposed by Respondent are reasonable and should be adopted.

Industrial Service Classification

Respondent proposed increases in demand, energy and transformation charges for the industrial service rates, Service Classifications 21, 24 and 30, and special contracts. Respondent proposes to implement time-of-day energy charges for industrial customers served under S.C. 21 and 24. The on-peak period will be 10:00 a.m. to 11:00 p.m. on week days, excluding certain holidays. Respondent's witness testified that the proposed on-peak energy charge of 2.85¢ per kwh was established based on Respondent's marginal energy costs during the primary and secondary peak periods. The proposed off-peak credit of 0.55¢ per kwh (resulting in an effective off-peak energy charge of 2.30¢ per kwh) was determined based on (1) analysis of the differential between primary peak-secondary peak and off-peak energy costs on both an embedded and marginal cost basis; (2) the need to maintain tailblock energy charges at least at short run marginal cost; (3) the need to ensure that total revenue requirements are recovered, particularly in light of the possibility of load shifting by customers in

response to an on-peak/off-peak differential; and (4) the need to avoid giving disproportionately large (e.g., 40% or greater) increases to individual customers as a result of the change in rate design.

The witnesses testifying on behalf of Bradley Park also recommended implementation of time-of-day rates for all industrial customers, but proposed much greater on-peak vs. off-peak differentials than proposed by Respondent. Their proposed final rate to recover 100% of the proposed revenue requirement was:

Summer peak kwh:	2.31¢/kwh
Winter peak kwh:	2.57¢/kwh
Off-peak kwh:	1.55¢/kwh
Summer capacity charge:	$21.85/kw per month
Winter capacity charge:	$ 0
Customer charge:	$5,980.56 per month

Based on the evidence heretofore reviewed concerning the impact on individual customers and given that Respondent's proposal represents the first attempt at implementing time-of-day industrial energy charges for Respondent's customers, the Commission is of the opinion that the on-peak/off-peak differential proposed by Respondent is the maximum that should be implemented at this time.

Witnesses testifying on behalf of the Industrial Power Users once again testified that rates should be based solely on embedded costs and submitted evidence that Respondent's proposed Rate 24 energy charges and on-peak/off-peak differential are excessive.

Industrial Power Users presented evidence that the ratios of "marginal" cost by time period bear absolutely no relationship to the "average" cost by time period and that average variable costs during the summer on-peak hours are only 2% higher than the average for the year. Industrial Power Users' witness testified that, when demand charges are understated and energy charges are overstated, wrong price signals and earnings instability result.

Respondent defended its proposed industrial charges as being appropriately based on marginal cost. Respondent's witness testified that Respondent's proposed industrial demand charge was approximately equal to the long run incremental cost of providing an additional kw of demand on peak, as determined by the cost of adding a combustion turbine peaking unit which would be the lowest-cost generation addition required to serve additional on-peak demand. He testified that the additional capital costs of base-load facilities are incurred not to meet peak demand but to serve customer energy requirements during all hours of the year at the lowest possible cost.

A witness for Respondent testified that Respondent's embedded cost of service methodology properly reflects the fact that additional customer energy requirements may cause the utility to construct additional capital-intensive base load plant to serve those requirements. In support of its analysis, Respondent also presented the testimony of a witness who demonstrated that as the system load factor (annual energy requirements) on a utility system increases, increased installation of base load plant is indicated. This results in increased installed cost of capacity per kw of peak demand and increased capacity-related revenue requirements per kw of peak demand as the system load factor increases.

With respect to Respondent's proposed industrial energy charges, the evidence shows that they are appropriate approximations to short run marginal energy costs, which Respondent's

witness testified is appropriate in order to insure that customers receive proper price signals concerning their consumption decisions, and to insure that the utility recovers the incremental cost of supplying additional energy. In response to the contention by the Industrial Power Users' witness that the proposed rate design would result in revenue instability, Respondent's witnesses testified that there is no evidence that industrial energy usage is less stable than industrial kw demands.

Respondent's witness presented evidence to show that the Industrial Power Users' proposed S.C. 24 was inappropriate because it would have to be applied to all subtransmission level industrial customers including those served on S.C. 21, and if so applied, would result in disproportionately high bill increases to many industrial customers.

The Commission is of the view that the time is long past when any proposal to base rates on embedded costs can be seriously considered. Respondent's proposed industrial rate design appropriately reflects marginal cost data in both the demand and energy charges, while taking into account other important considerations such as customer impact in the design of the on-peak/off-peak differential. Further, there is no evidence to support the assertion by the witness for the Industrial Power Users that the proposed rate design will lead to disturbing earnings instability; on the contrary, it appears that the proposed rate design will more accurately reflect the cost consequences of additional kw and kwh consumption than would the alternative rate form proposed by Industrial Power Users' witness. The Commission is therefore of the opinion and finds that the industrial rates and rate design proposed by Respondent are reasonable and should be adopted.

The Commission is of the opinion that tailblock energy charges should be set at short-run marginal energy cost as proposed by Respondent, in order to provide proper price signals. Accordingly, in any revisions to its filed tariffs which Respondent may be required to make in order to recover the revenues allowed by this Order, Respondent should maintain tailblock energy charges at the levels proposed. However, if there are customers, such as Electroschmelzwerk Kempten GMBH (ESK) or customers taking interruptible service, for whom Respondent has proposed increases only in the energy charges, Respondent may alter such energy charges so that such customers do not receive disproportionately high increases in relation to the total revenue increase allowed herein, and so that current relationships between interruptible and firm rates are maintained.

Municipal Service and Lighting Service Classifications

Respondent proposes increases in the municipal service rates, S.C. 41 and 42, and the lighting rates, S.C. 39 and 45. Respondent also proposes to eliminate prospectively the contract term discount in S.C. 41 and 45, because there is no longer any cost justification for it. The discount will be eliminated prospectively because legal considerations prohibit its elimination for customers who have contract ordinances in effect.

The Commission finds that the municipal service and lighting rates and rate design proposed by Respondent are reasonable and should be adopted.

Conclusion

With the exceptions noted above, the Commission finds Respondent's proposed rate design appropriate. Respondent should reduce the proposed tariff filing to the revenue award embodied in this Order in the manner proposed by Staff. Therefore, Respondent should reduce each customer class (S.C. 1 and S.C. 2 should be considered one class for this purpose) proportional to Respondent's proposed increase to each class, and within each class, by reducing the demand charge or the demand component of each rate. Energy charges should be adjusted, as necessary, to reflect the Commission's decision to maintain Respondent's existing fuel adjustment clause as hereinafter discussed.

Adoption of Uniform Fuel Adjustment Clause

As part of its filed tariff sheets, Respondent included a new fuel adjustment clause ("Rider F") in the form of the Uniform Fuel Adjustment Clause published by the Commission in the Illinois Register on July 18, 1980 as proposed General Order 211. The design of Respondent's proposed base tariff charges, and Respondent's estimates of the revenue effect of the proposed tariff revisions, were based on the assumption that the proposed fuel adjustment clause would be adopted. Staff proposed revenue and fuel expense adjustments if Respondent was allowed to adopt the Uniform Fuel Adjustment Clause in this Order. The Commission is of the view that Respondent's proposed fuel adjustment clause should not be allowed to go into effect until General Order 211 is adopted. Implementation of the uniform clause is premature at this time. Staff's proposed adjustments to revenue and fuel expense therefore should not be adopted.

A witness testifying on behalf of the Industrial Power Users recommended that the fuel adjustment clause be zero-based, and that the clause provide for differential charges for customers taking service at different voltage levels to reflect differing line losses incurred in serving customers at different voltage levels. The Commission has reviewed the entire record in this proceeding including the testimony of this witness and the rebuttal offered by Respondent's witness and finds that the recommendations of the Industrial Powers Users' witness should not be adopted.

THE PUBLIC UTILITY REGULATORY POLICIES ACT

In November 1978, the U.S. Congress enacted the Public Utility Regulatory Policies Act as part of the National Energy Act. The expressed purposes of PURPA are to encourage: (1) conservation of energy supplied by electric utilities, (2) optimization of the efficiency of use of facilities and resources by electric utilities, and (3) equitable rates to electric consumers. Section 111(a) of PURPA provides that each state regulatory authority should consider the ratemaking standards established in Section 111(d), and determine whether or not it is appropriate to implement such standards.

Consideration of PURPA Standards

Considerable evidence was taken on the topic of compliance with the six electric utility ratemaking standards of Section 111(d) of PURPA, which were the subject matter of Docket No. 80-0365. Although witnesses differed in their interpretations of the requirements of the statute, no witness explicitly recommended that any of the six standards be rejected totally. Respondent's witness testified that the most important criteria for determining whether and to what extent to implement any of the six ratemaking standards is cost-effectiveness, since if a standard was adopted which was not cost effective two of the three purposes of PURPA would not be furthered, namely: optimization of the use of facilities and resources and encouragement of equitable rates for consumers.

Cost-of-service standard

The greatest controversy was engendered by the cost of service standard of Section 111(d)(1). A Commission Staff witness, as well as a witness appearing on behalf of Bradley Park, testified that only basing rates on marginal cost data would satisfy the PURPA cost of service standard, while three witnesses for Industrial Power Users and a witness for the Department of Defense testified that only basing rates on embedded costs would

satisfy the standard. The arguments offered by the latter witnesses have previously been summarized herein. Respondent's witnesses testified that both marginal and embedded cost data should be considered in the design of rates and that rates should be based on cost data to the extent compatible with other considerations relevant to ratemaking including historical continuity of rate design, avoidance of disproportionate increases to particular classes of individual customers due to changes in rate design, earnings stability, effectiveness in yielding total earnings requirements, customer understanding and value of service.

A Staff witness from the Commission's Economics and Rates Department testified on the role of both marginal and embedded cost of service studies. That witness testified that both short-run and long-run marginal cost of service studies should be utilized in both rate design and in determining inter-class revenue requirements. The witness indicated that the use of marginal cost studies becomes critical when the results of the embedded studies vary significantly from the results of the marginal studies. The witness indicated that failure of rates to reflect marginal costs could be very costly to consumers and the utility. Embedded cost of service studies do not reflect the opportunity costs of a consumption decision which a marginal cost of service study reflects. Marginal costs, therefore, should be the primary input into both rate design and inter-class revenue requirements. The witness recommended that in future cases, in addition to its marginal cost of service studies, Respondent should prepare a study on inter-class revenue requirements based on marginal costs. The Commission adopts the Staff's recommendation.

In its April 15, 1981 Order in Union Electric Company, supra, the Commission stated that marginal costs should be used in setting proper charges for electric service. Section 111 of PURPA requires a determination of the appropriateness of implementing the PURPA standards "with respect to each electric utility for which it has ratemaking authority" (emphasis supplied). The Commission is of the opinion that the record herein supports a similar conclusion.

The Commission has already in this Order stated its opinion that marginal cost should be utilized in setting electricity prices and that other considerations analyzed by the parties should be considered in the rate design process. The extent to which Respondent's proposed rates reflect cost and other considerations has been discussed in previous sections of this Order.

Declining block, seasonal, and interruptible rate standards

A Staff witness from the Commission's Economics and Rates Section testified that Respondent's proposed rates satisfy the declining block, seasonal and interruptible rate standards of Sections 111(d)(2), 111(d)(4) and 111(d)(5) of PURPA. With respect to the declining block rate standard, Respondent presented evidence to show that those of its proposed rates which do contain declining blocks are composed of an energy cost recovery portion which is flat across all kwh, plus a demand cost recovery component in the initial blocks.

Respondent showed that its proposed residential rates are flat in the summer season and have 2 blocks in the winter season. Respondent's witness testified that the second winter energy charge block reflects winter weather-sensitive usage (space heating) which Respondent's studies show bears no demand cost responsibility. The Commission recognized this as an appropriate basis for winter energy charge blocking in its recent Order in Union Electric Co. supra, at p. 4.

Respondent further showed that it was implementing demand metering for those customers for which demand metering is cost-

effective, in order to be able to charge separately for demand-related costs. It was the opinion of witnesses testifying on the subject, and a reading of the statute indicates, that the PURPA declining block standard only applies to the energy-cost recovery portion of the rate schedule.

With respect to seasonal rates, Respondent presented evidence to show the extent to which seasonal cost differences are reflected in the energy charge and/or demand charge portions of its various rate schedules. The record shows that 98% of Respondent's retail kwh are sold under rate classifications which contain seasonal energy and/or demand charges.

In connection with interruptible rates, Respondent presently makes available interruptible service to all customers with demands greater than 500 kw; that to offer interruptible rates to customers with smaller demands is not likely to be cost effective due to the extensive monitoring and implementation costs associated with interruptible rates, but that Respondent stands ready to negotiate a special interruptible rate with any customer where such a rate would be mutually beneficial; and that Respondent also offers interruptible service to industrial customers under Rider S, which enables customers to purchase, on an interruptible basis, additional energy during on-peak periods at incremental energy costs without incurring additional demand charges.

In summary, the evidence presented shows that the Staff witnesses' conclusion that Respondent has implemented the declining block, seasonal and interruptible rate standards of PURPA is acceptable pending review in future cases.

Time-of-day rates and load management standards

A Staff witness testified that Respondent has made partial implementation of the time-of-day rate standard of Section 111(d)(3) of PURPA and is proceeding to further implementation of that standard in light of the ongoing cost-benefit analysis it requires. It should be noted that while there was debate on the record concerning the extent to which and speed at which time-of-day rates should be implemented for large residential and large commercial customers, there is no debate that implementation of time-of-day rates is cost-effective for industrial customers and probably not cost-effective for small residential, small commercial and municipal customers.

The extent to which Respondent is offering time-of-day rates has been discussed in the preceding section of this Order. The Commission is of the opinion and finds that the Staff witnesses' opinion is correct and that Respondent is implementing the time-of-day standard in a timely manner. In future rate cases the Company should present cost/benefit studies analyzing time-of-day rate implementation where cost of metering is significant.

The Staff witness further testified that Respondent is implementing the load management standard of Section 111(d) (6) by virtue of a number of experimental programs which it is conducting in the area of direct load control and other load management activities. Respondent's witness testified on Respondent's current load management activities including residential home energy audits; energy management programs for commercial and industrial customers; experiments in direct control of residential electric water heater load; and research programs in solar-assisted water heating, more efficient use of heat pumps, more energy efficient motors, power factor controllers and similar devices, waste heat utilization, and use of wind power for generation. The record demonstrates, and the Commission concludes, that Respondent's ongoing research and energy management activities constitute compliance with the load management standard of Section 111(d)(6) of PURPA. In future rate cases the Company should present cost/benefit studies of their load management programs and an analysis of customer reaction to them.

Based on all the evidence, the Commission is of the opinion and finds that the six electric utility ratemaking standards of Section 111(d) of *PURPA* are appropriate and should be adopted and implemented by Respondent to the extent implementation is cost effective. The Commission is further of the opinion and finds that Respondent is striving to implement all six standards to the extent implementation is cost effective at this time.

FINANCIAL CONDITION AND FINANCING REQUIREMENTS OF RESPONDENT

Much of the evidence presented in this case concerning Respondent's need for an increase in its electric rates related to Respondent's requirements for raising capital to finance its construction program, principally consisting of construction of Clinton Unit No. 1, and present and foreseeable economic and financial conditions bearing on Respondent's ability to raise capital from external sources. At December 31, 1980, Respondent had a total capitalization of $1,999,476,100 and net electric utility plant in service of $1,029,986,748.

Respondent's witness testified that Respondent plans electric utility construction expenditures for the period 1981 through 1983 of $883 million and plans outside financings during the years 1981-1982 of approximately $522 million if no rate increase is granted. An additional $125 million of nuclear fuel financing must be accomplished through Illinois Power Fuel Company whose obligations are guaranteed by Respondent and whose financial statements may be consolidated with Respondent's by security rating agencies for purposes of determining Respondent's credit rating.

Respondent's evidence showed that it had an investment in Construction Work in Progress ("CWIP") at December 31, 1980 of $927,115,748 or approximately 49% of its total capitalization, and that CWIP will increase to $1,422,201,000 at December 31, 1982 at which time it is expected to constitute 57.6% of total capitalization.

Evidence presented in this proceeding showed that the recent period has been characterized by economic recession and high inflation which has been reflected in the capital markets by high interest rates associated with both short-term and permanent financings. The record shows that in 1980, short-term interest rates were as high as 19.77% and averaged 11-15% for the year; the average yield on new AA utility bonds was over 13%; and utility preferred stock yields exceeded 11.5%. Data was presented to show that inflation has seriously affected the market for utility common stocks, the market prices of which have declined substantially in recent years.

A witness testifying on behalf of Respondent stated that investors have become disenchanted with Respondent's and other utilities' common stocks due to their comparatively low growth in earnings per share, market price, book value and dividends; the high cost of new senior capital; and the sale of utility stock below book value. He also testified based on a review of recent economic trends and conditions that the economic trends and conditions, particularly high inflation, which have adversely affected utility financial integrity and the capital markets will continue in the 1980-1982 period, resulting in rising cost of senior capital, difficulties in maintaining adequate interest coverages, declining utility stock prices, and negative investor attitudes towards utility securities. The effect of all this data is to show that it will be extremely difficult for utilities including Illinois Power to raise capital in the near term and that capital raised from external sources will be obtained at high costs compared to historical levels.

Considerable evidence was presented on the recent and foreseeable financial condition of Respondent. A witness testified

for Respondent on appropriate measures of financial integrity, which he defined as a condition in which a utility has sufficient financial strength to raise needed capital in good and bad market conditions at reasonable costs and with rates to customers that are fair and rates of return to stockholders that are fair. The witness testified that a utility maintains financial integrity if it: (1) maintains high quality bond ratings, that is AA; (2) generates at least 50% of its construction cash requirements internally; (3) sells new common stock at or above book value after market pressure and issuance cost; (4) possesses adequate financial strength or a sufficiently high common equity ratio and has adequate financial flexibility; (5) earns a fair return of good quality on invested capital in order to compete for capital at reasonable cost; and (6) charges rates to customers that are no higher than necessary to maintain a satisfactory level of financial integrity.

Respondent presented evidence on its historical performance compared to other similarly-rated utilities and its forecasted performance as measured by certain financial data which were identified as indicators of the above measures of financial integrity. Historical and forecasted data under various rate increase scenarios was presented with respect to the following statistics: (1) interest coverage before income taxes, including an allowance for funds used during construction ("AFUDC") (a measure of interest coverage); (2) interest coverage before income taxes, excluding AFUDC (a measure of cash coverage of interest obligations); (3) internal cash generation as a percent of additions to utility plant (a measure of internal cash generation and cash flow); (4) AFUDC as a percent of earnings applicable to common stock (a measure of quality of earnings); (5) return on average common stock equity (a measure of return to the common stock holder); and (6) ratio of total debt to total capitalization plus notes payable (a measure of capital ratio flexibility). Respondent also showed financial goals which it has established with respect to each of these statistics in order to maintain its financial integrity and its relative credit standing compared to other AA utilities.

Evidence presented by Respondent's witness showed that, with the exception of the last statistic above listed, Respondent's financial statistics were worse during 1975-1979 than the average for the twenty other utilities carrying AA first mortgage bond ratings according to Moody's and Standard & Poor's rating services during the same period. A similar presentation was made by the Accounts and Finance Department of the Commission whose witness presented data for the period 1975-1979 and the year 1979 on 20 key credit and equity analysis ratios for Respondent and for all utilities with, respectively, AAA, AA, and single A security credit ratings.

Data was presented by the Staff on statistics such as interest coverage including AFUDC, interest coverage less AFUDC, internal cash generation as a percentage of total debt times dividend earned through internal generation, internal cash generation as a percentage of construction expenditures, return on average equity, AFUDC as a percentage of earnings, dividend payout ratio, dividend yield, market to book ratio, and price-earnings ratio. The data presented by Staff demonstrated that (1) the financial statistics for Respondent deteriorated during the five-year period; (2) Respondent's statistics with respect to almost every financial ratio were worse than the average for all AA utilities, and in some cases were more comparable to the average for single A companies; and (3) the disparity between Respondent's financial performance and that of other AA utilities in the last year analyzed, 1979, particularly with respect to ratios pertaining to cash flow, including interest coverage less AFUDC, internal generation as a percentage of total debt times dividend earned through internal generation, internal generation as a percentage of construction expenditures, and AFUDC as a percentage of earnings.

Respondent presented forecasts of its financial performance as measured by the six financial statistics which it utilized for this purpose during the period 1980 through 1982 if it receives no rate increase. Forecasted data presented by Respondent showed decline in Respondent's financial integrity, and inability to maintain a position comparable to that of other AA rated utilities. The Company evidence showed poor performance with respect to those statistics relating to Respondent's cash position, including interest coverage excluding AFUDC, internal cash generation as a percent of additions to utility plant, and AFUDC as a percent of earnings. Additionally, forecasted information was presented by Illinois Power on other financial indicators including earnings per share, cash flow per share, and internal cash generation as a percent of debt. All of this evidence showed Respondent's financial position would decline during the next 2 1/2 years.

Respondent's witness testified that if no electric rate increase was granted, Respondent would need to issue $125 million of long term debt during the second half of 1981 in order to have sufficient cash to continue its construction program; but that Respondent's interest coverages computed in accordance with its mortgage indenture will not permit the issuance of more than $75 million of first mortgage bonds after mid-year 1981, and will not permit the issuance of any first mortgage bonds after year-end 1981. Under these circumstances, and if Respondent's securities were downgraded from AA to single A, Respondent states it would be required to sell $125 million of debentures which would carry a higher interest rate (forecasted by Respondent to be 15%) than first mortgate bonds. The Company witness testified that if first mortgage bonds were downgraded, Respondent's preferred stock would also be downgraded to single A, resulting in a higher cost for a sale of $35 million of preferred stock planned for 1981. This witness also testified that in 1982 Respondent would again have to sell debentures rather than first mortgage bonds, and would exhaust its ability to sell preferred stock under the coverage test of its Articles of Incorporation necessitating the sale of preference stock at a higher rate of interest. Respondent claims it would also expect to be able to sell about $30 million less of common stock than planned due to its inability to earn its dividend and its unsatisfactory financial condition.

Witnesses testifying on behalf of OCS also presented testimony and exhibits pertaining to Respondent's present financial condition and ability to raise capital. One OCS witness presented testimony concerning factors reviewed by security rating agencies in establishing utility credit ratings and on comparisons of Respondent's financial performance to that of other AA utilities. The witness noted that Respondent sold first mortage bonds in 1980 at yields to maturity of 11.45% for seven-year bonds and 12.70% for thirty-year bonds which he characterized as reasonable costs. The witness offered his opinion that Respondent compares favorably to other utilities, is not in financial jeopardy and will continue to be able to raise capital at reasonable cost without a rate increase.

This witness and a second witness on behalf of OCS testified that certain financial goals utilized by Respondent as a measure of its financial integrity and standing compared to other AA utilities did not need to be achieved for Respondent to maintain its present AA first mortgage bond and preferred stock ratings. Their evidence was offered in support of a conclusion that the Commission should not rely on Respondent's financial conclusions in determining the amount of rate relief to be granted.

The Assistant Director of OCS presented an exhibit which showed the performance of each AA utility in each year 1975-1979 with respect to the six financial statistics used by Respondent. The data showed that in each year many of the utilities did not achieve the financial goals which Respondent has established.

An OCS witness also presented an exhibit which showed certain financial statistics compiled by an investment banking firm for AAA, AA, and single A utilities for 1975-1979. The witness used this data to present a comparison of AA and single A utilities for this period. The presentation showed that AA utilities had, as a group, higher pre-tax interest coverage including AFUDC, higher pre-tax interest coverage excluding AFUDC, higher return on average common equity, and a lower debt ratio, than did single A utilities. AA and single A utilities had equivalent averages for AFUDC as a percentage of earnings available for common, both 28%; and AA utilities had a lower internal cash generation as a percentage of construction expenditures than did single A utilities, 45.9% versus 63.9%. It is to be observed from the witnesses' exhibit that for the same period Respondent had AFUDC as a percent of earnings of 32.6% and internal cash generation as a percentage of construction expenditures of 33.74%; in 1980, Respondent had AFUDC as a percentage of earnings of 54.2% and internal cash generation as a percentage of additions of 24.0%.

OCS witnesses also presented several forecasts for periods before and after the in-service date of Clinton Unit No. 1. These forecasts, some of which assumed the granting of the full rate increase requested herein and others of which assumed the granting of a somewhat smaller rate increase (e.g. $65.3 million) in July 1981, were offered in support of a conclusion that Respondent's financial condition, particularly its internal cash generation, will improve substantially after Clinton Unit No. 1 is placed in service and in rate base at its full completed cost and the corresponding rate increase allowed to go into effect. OCS' Assistant Director testified that Respondent's present financial position is only a temporary condition resulting from the burden of constructing a nuclear generating unit which involves a long lead time, higher construction costs and high financing costs.

The Commission is fully cognizant that Respondent's financial condition should improve after the in-service date of Clinton Unit No. 1; however, the evidence indicates that Respondent faces significant burdens in the near-term to finance its construction program which must be met if the project is not to be delayed and if unreasonable capital costs are to be avoided. The Commission finds no need to draw conclusions with respect to the ability of predicting downgradings of Respondent's securities by reference to a specific set of financial statistics. However, the record indicates that Respondent's financial performance during the recent past and forecast for the near term, as measured by numerous financial statistics, is inferior to that of other AA utilities; and that leading security rating agencies presently view Respondent's internal cash generation, cash flow and debt coverages to be marginal for continued maintenance of AA security ratings.

The Commission has reviewed all the financial statistics, historical and forecasted, presented by witnesses in this case relating to Respondent's financial performance and that of other utilities as well as the evidence presented on Respondent's construction and financing requirements and general economic and financial market conditions. It is apparent from this data that it will be difficult to raise capital in external financial markets on reasonable terms, that Respondent has very substantial financing requirements during the next several years and will be required to raise a large amount of capital in relation to its existing capitalization and that Respondent's ability to do this on reasonable terms will be seriously impaired unless its financial integrity is maintained at reasonable levels. The statistical data presented indicates that Respondent's financial condition has been deteriorating during the last several years relative to comparably-rated utilities. The Commission has fully evaluated all this evidence, and its specific findings and conclusions hereinafter set forth in relation to rate base, operating income and rate of return all reflect due consideration of this evidence.

TEST YEAR

Witnesses testifying on behalf of Respondent presented data on the net original cost of Respondent's utility plant at December 31, 1980 and actual operating results for the twelve months ended December 31, 1980; and detailed forecasts of Respondent's financial position, utility plant and operating results for forecasted periods including the twelve months ending June 30, 1982, which would be approximately the first full year following the issuance of this Order. The witness testifying on forecasted information also presented a thorough and detailed statement of the procedures used by Respondent to develop its forecast and the underlying data and assumptions utilized in the forecast.

Respondent's witnesses also presented exhibits showing adjustments to historical and forecasted operating results appropriate for ratemaking purposes. A witness associated with a valuation engineering firm presented evidence on the trended original cost and trended original cost less depreciation of Respondent's utility plant in service at December 31, 1980 from which evidence Respondent developed proposed fair value rate bases for the twelve months ending December 31, 1980 and June 30, 1982. Respondent's Vice President presented proposed original cost and fair value rate bases and proposed operating income statements for the 1980 and June 30, 1982 test years.

The Commission is of the opinion that the twelve month period ending December 31, 1980 provides the appropriate basis for determining the test year data to be used for purposes of this proceeding. The Commission has, however, reviewed all the forecasted data presented by Respondent including information on procedures and assumptions supporting its forecasts.

ELECTRIC RATE BASE

Original Cost Rate Base

Respondent's Exhibit 1.27, p. 1, showed the following original cost rate base before adjustments at December 31, 1980:

ORIGINAL COST RATE BASE BEFORE
ADJUSTMENTS - DECEMBER 31, 1980

Item	Amount (000)
Original cost of plant in service	$1,544,400
Reserve for depreciation	(514,413)
Net original cost of plant in service	1,029,987
Land held for future use	17,284
Construction work in progress	97,064
Small projects - construction work in progress	370
Materials and supplies	20,268
Electric fuel inventory	66,773
Accumulated provision for deferred income taxes	(143,538)
Contributions in aid of construction	(10,631)
Customer advances for construction	(1,362)
Subtotal	46,228
Net original cost rate base	$1,076,215

Original Cost Rate Base - December 31, 1980

Respondent showed in IP Ex. 1.27 and 11.29 admitted in evidence its proposed rate base adjustments and net original cost rate base at December 31, 1980. Respondent proposed the following original cost rate base applicable to a 1980 test year:

ORIGINAL COST RATE BASE, WITH
ADJUSTMENTS-DECEMBER 31, 1980

Item	Amount (000)
Original cost of plant in service	$1,543,449
Reserve for depreciation	(513,193)
Net original cost of plant in service	1,030,256
Rate base adjustments	
Land held for future use	12,138
Construction work in progress	510,000
Small projects-construction work in progress	370
Materials and supplies	20,147
Electric fuel inventory	61,842
Accumulated provision for deferred income taxes	(143,538)
Contributions in aid of construction	(10,631)
Customer advances for construction	(1,362)
Jurisdictional allocation	(58,475)
Total rate base adjustments	390,491
Net original cost rate base	$1,420,747

Respondent's proposed rate base adjustment for land held for future use included only that land held for future use which has a definite in-service date within ten years, in accordance with established Commission practice. Respondent also adjusted original cost rate base by deducting electric merchandise inventory; deducting investment in electric leased appliances and applicable depreciation reserve; and reducing the reserve for depreciation by the cumulative amount of depreciation expense applicable to contributed property. Respondent also proposed adjustments for jurisdictional allocation and electric fuel inventory which are discussed below.

Jurisdictional Allocation

Respondent presented a rate base adjustment to deduct from retail base plant items allocated to non-jurisdictional customers, in compliance with the Commission's directive in its Order in Docket No. 79-0071, requiring Respondent to file in all future rate cases a cost of service study performed in accordance with Federal Energy Regulatory Commission ("FERC") guidelines to enable the Commission to remove from jurisdictional rate base, revenues and expenses the rate base, revenues and expenses attributable to non-jurisdictional operations.

Respondent's witness testified that the adjustment was prepared by first computing rate base and operating expenses for 1980 for the total Company using cost of service methods accepted by FERC; then allocating rate base and expense items to each of the three wholesale classes served by the Company using the allocation methods specified in the most recent FERC rate order or which were used as a basis for the most recently-negotiated rate settlement accepted by FERC for each wholesale class served by Respondent. The witness testified that this approach assures that no rate base or expense item is excluded from determination of overall revenue requirements. The rate base and expense items determined for each class were then added to obtain the total amount allocated to the wholesale class.

A witness testifying on behalf of the Department of Defense posed two criticisms of Respondent's jurisdictional allocation. First, he testified Respondent should have

performed the allocations using the twelve concident peak ("12 CP") allocation method which he stated is required by FERC and its staff. Second, he objected to Respondent's use of average monthly plant balances to calculate amounts to be deducted from year-end rate base.

On rebuttal, Respondent's Director of Economic Research showed that FERC has no published guidelines requiring use of the 12 CP method; that the FERC has approved rate settlements between Respondent and its wholesale customers based on other allocation methods; and that it has used other methods in deciding contested cases involving other utilities including another Illinois utility. The witness also showed that FERC used average monthly plant balances to determine the wholesale rate bases on which Respondent's wholesale rates are based and that Respondent's approach therefore properly matches wholesale rate base to the wholesale revenues actually collected.

The Commission has reviewed the allocation study presented by Respondent and the jurisdictional allocation adjustment proposed by Respondent. The Commission is of the opinion that Respondent's methodology complies with the Commission's directive stated in Docket No. 79-0071, is reasonable and appropriate, and should be adopted for purposes of this proceeding.

Electric Fuel Inventory

Respondent proposed a rate base allowance for electric fuel inventory of $61,842,000 based on the actual amount of inventory at December 31, 1980 ($66,773,000) adjusted to reflect Respondent's target coal inventory levels of 70 days supply at all plants and 90 days supply during five winter months at two plants which receive coal by barge; and further adjusted to reflect average inventory prices for coal and oil forecasted to be in effect during the twelve months ending June 30, 1982.

Respondent's witness testified that allowance for a 90-day supply at the two plants served by river transportation for the five winter months was necessary to insure adequate coal supplies at these stations during periods when barge traffic may be impeded by freezing, flooding or low water on the waterways on which the fuel supply is transported. He calculated that use of a 70-day coal supply at all stations and a 90-day coal supply for five winter months at the two stations served by river transportation results in a system average coal supply of 71.4 days on an annual basis. The witness also testified that repricing of fuel inventory to reflect price levels forecasted for the twelve months ending June 30, 1982 was necessary so that the rate base adjustment for fuel inventory would represent the investment required to support Respondent's fuel inventories during the first full year that new rate levels will be in effect.

Data was presented in evidence to show that the price of coal per ton and oil per gallon held in inventory by Respondent has increased steadily over the recent historical period. Respondent's witness, who presented forecasted information, testified on the manner in which Respondent forecasted the fuel prices, on a plant-by-plant basis and separately for fuel costs and transportation costs, on which the proposed price adjustments to fuel inventory were based.

A Staff witness from the Commission's Economics and Rates Section proposed that fuel inventory be based on an allowance of a 70-day supply at all plants and a 90-day supply for three winter months at the two stations served by river transportation; and that the inventory be priced at the most recent available historical prices which were those at February 28, 1981.

The Staff witnesses' proposed adjustment to electric fuel inventory amounts to a reduction of $5,286,000 from the Company's proposed original cost rate base. Inasmuch as coal deliveries on the waterways may be reduced for the period January through March and the most current inventory price is more reliable than the price forecasted for June 30, 1982 as proposed by the Company, the Commission is of the opinion that Staff's fuel inventory adjustment should be adopted.

Based on the foregoing considerations and its review of all the evidence in this proceeding, including its determination with respect to construction work in progress as hereinafter discussed, the Commission is of the opinion and finds that Respondent's net original cost rate base at December 31, 1980 which should be utilized for purposes of this proceeding is $1,280,090,000.

Fair Value Rate Base

A witness in a valuation engineering firm, testifying on behalf of Respondent, presented evidence on the trended original cost and trended original cost less depreciation of Respondent's utility plant at December 31, 1980. The witness testified that he determined the current cost of Respondent's electric utility plant using a trending method based on both the Handy-Whitman method and, where necessary, indices specific to Illinois Power which he prepared. He testified that the trending method was used because it is the fastest and least expensive method to estimate current cost and has the advantage of starting from recorded original cost.

Custom indices specific to Respondent were developed to obtain greater precision on accounts where indices based on national, regional or local averages might not properly reflect Respondent's experience. The data used to compile the specific indices was taken from the books and records of account maintained by Respondent. The witness presented the following summary of trended cost and trended cost less depreciation at December 31, 1980:

Item	Trended Cost (000)	Trended Cost Less Depreciation (000)
Intangible plant	$ 527	$ 500
Production plant	1,771,453	1,255,000
Transmission plant	424,685	282,500
Distribution plant	1,053,868	628,000
General plant	104,613	59,000
Total depreciable plant	3,354,619	2,224,500
Land	24,256	25,000
Total	$ 3,379,402	$ 2,250,000

The witness testified that he included hydraulic production plant, which is fully depreciated, and land and land rights at original cost; excluded leased property on customer premises, which the Commission has previously excluded from rate base; and made allocations of property to the gas utility. He further testified that the amount of depreciation deducted from trended cost was equivalent to the ratio of book depreciation to original cost. According to Respondent's witness this method, which the Commission has utilized in recent fair value cases, produces a larger depreciation deduction than would a more accurate depreciation study, and therefore results in a conservative value for trended costs less depreciation.

The Commission is of the opinion and finds that the trended cost and the trended cost less depreciation as presented by Respondent's witness is reasonable and should be adopted for purposes of this proceeding.

Respondent's Vice President presented a fair value rate base determined on a weighting of 75% net original cost and 25% trended cost less depreciation which has been used by the Commission in recent fair value decisions. The witness presented the proposed fair value rate base with adjustments on IP Ex. 11.30 admitted in evidence.

Based on all the evidence and considerations, including the trended cost less depreciation of Respondent's utility plant at December 31, 1980; the net original cost of the utility plant at December 31, 1980; the weighting utilized by Respondent's witness; and the rate base adjustments discussed in this Order, the Commission is of the opinion and finds that the fair value electric rate base at December 31, 1980 which should be utilized for purposes of this proceeding is $1,585,400,000.

ELECTRIC UTILITY OPERATING REVENUES, EXPENSES AND INCOME

1980 Operating Results

Respondent presented the following statement of its actual operating results for the calendar year 1980:

Item	Amount (000)
Operating revenues	$ 567,357
Operating expenses	
Fuel for electric plants	240,601
Power purchased for resale	6,527
Power interchanged - Net	(40,452)
Operation and maintenance	94,729
Depreciation and amortization	48,838
Taxes other than income taxes	51,274
Federal income taxes-current	18,437
State income taxes-current	6,529
Provision for deferred income taxes	21,101
Income taxes deferred in prior years	(3,849)
Investment tax credit deferred-net	22,159
Total operating expenses	456,894
Operating income	$ 101,463

Proposed Revisions to Electric Depreciation Rates

Based on the recommendation of the civil engineer testifying on its behalf who presented the results on his review of Respondent's present electric depreciation rates, Respondent proposed the following revisions to its electric depreciation rates:

Electric Depreciation Rates

Function	Present		Proposed
Production			
Steam	2.95%		3.32%
Other-Diesel	3.00		3.00
-Combustion turbine	4.00		4.00
Hydraulic		Fully depreciated	
Transmission	2.98		2.98
Distribution	4.00		3.35
General			
Transportation and power operated equipment	20.00		7.99
Other	3.54		3.515
Composite	3.4		3.3

The witnesses' principal recommendations for changes in depreciation rates pertain to the steam production and distribution functions. His recommended increase in the depreciation rate for steam production plant was based on the following factors: (1) the depreciation rate for steam production plant is a function of the production life of the facilities, the number of interim retirements, the number of interim additions, and salvage value or removal cost; (2) the original invested capital should be recovered by age 35, when the typical station has produced about 80% of its total lifetime production; (3) the investment in interim additions and retirements should be recovered in less than 35 years to achieve total recovery at age 35; and (4) industry data supports removal cost in excess of salvage value of 5%.

The proposed depreciation rate for steam production plant was reviewed by a Staff witness from the Commission's Economics and Rates Department, who concluded that the proposed rate was reasonable and consistent with rates used by other Illinois utilities.

The recommended change in the depreciation rate for distribution plant was based on an analysis of average service lives based on Company property records, and on simulated plant balance and retirement rate methods for unidentified mass accounts. Respondent's witness testified that he used Equal Group Life accruals to match depreciation to actual consumption of capital in the distribution function. He testified that this method avoids under-accrual and over-accrual for individual units at retirement.

The Commission has reviewed the testimony and report of Respondent's witness pertaining to the recommended revisions to electric depreciation rates. The Commission is of the opinion based on this evidence that the proposed rates are reasonable and appropriate and should be approved; and that the proposed depreciation rates should be utilized as appropriate for ratemaking purposes in this proceeding.

Electric Operating Income
12 Months Ended December 31, 1980

Respondent showed in evidence the adjustments which it proposed be applied to historical 1980 operating income data for ratemaking purposes. The operating income statement proposed for use in connection with a 1980 test year was shown by Respondent to be the following:

ELECTRIC OPERATING INCOME, WITH ADJUSTMENTS
TWELVE MONTHS ENDED DECEMBER 31, 1980

Item	Amount (000)
Operating revenues	$523,472
Operating expenses	
Fuel for electric plants	240,601
Power purchased for resale	6,527
Power interchanged - net	(40,452)
Operation and maintenance	108,438
Depreciation and amortization	48,052
Taxes other than income taxes	42,351
Federal income taxes-current	1,067
State income taxes-current	3,602
Provision for deferred income taxes	21,103
Income taxes deferred in prior years	(3,849)
Investment tax credit deferred-net	22,159
Jurisdictional allocation	(26,261)
Total operating expenses	423,338
Operating income	$100,134

Respondent's proposed 1980 operating income statement reflected the following adjustments which were not contested by any party: (1) Operating revenues were reduced by the amount of revenues received from wholesale sales in 1980 and operating expenses were reduced by the amount of expenses allocated to the wholesale classes; (2) operating expenses were adjusted to exclude the effect of the Company's electric merchandising activities, membership dues and fees in certain civic and social clubs and the cost of analysis of proposed legislation and certain public information costs; (3) operating revenues and expenses attributable to Respondent's appliance leasing business were removed; (4) depreciation and amortization expense were reduced by the amount attributable to contributed property; (5) operating revenues and taxes were reduced to reflect the removal of the 2% excess State Public Utility Tax and various Municipal Utility Taxes; (6) current and deferred state income taxes were adjusted to reflect the reduction effective January, 1981 of the additional state income tax rate from 2.85% to 2.5%; (7) depreciation and amortization expense was adjusted to reflect the effect of the depreciation rate changes proposed by Respondent; (8) taxes other than income taxes were adjusted to reflect increased FICA tax expense applicable to the electric utility based on the change in the social security tax laws effective January 1, 1981 which increases the FICA base and rate from $25,900 at 6.13% to $29,700 at 6.65%; and (9) operating revenues and expenses were reduced by the amount of revenues and expenses associated with plant held for future use which was excluded from rate base because it did not have a definite in-service date within ten years.

Respondent's proposed operating income statement included adjustments reflecting the effect on interest expense and income tax deductions of utilizing the weighted average embedded cost of long term debt during the twelve months ending June 30, 1982 in determining the fair rate of return as proposed by Respondent and hereinafter discussed. This adjustment was contested by a Staff witness from the Commission's Accounts and Finance Department who presented an alternative interest expense-income tax adjustment based on the change in embedded rates of long term debt and preferred stock he anticipated to result from financings planned by Respondent during the twelve months ending June 30, 1982. The Commission is of the opinion that Staff's proposed adjustment to interest expense and income tax deductions is more reliable and should be utilized for purposes of this proceeding.

Respondent also proposed adjustments to reflect increases in operation and maintenance ("O&M") expense, invested capital tax expense, and real estate tax expense, on a cents per kwh basis, anticipated by Respondent during 1981. Each of these adjustments was opposed by a witness for the Department of Defense and a Staff witness from the Commission's Accounts and Finance Department as being outside the 1980 historical test period. The three adjustments proposed by Respondent are discussed below.

Proposed Adjustment to Operation and Maintenance Expense

Respondent adjusted O&M expense to reflect unit cost levels anticipated during the twelve months ending June 30, 1982. The adjustment to O&M expense proposed by Respondent was $13,652,841. Respondent argued that the adjustment was calculated in the same manner as the adjustment utilized by the Commission, in Respondent's last rate case, Docket No. 79-0071, as well as in Commonwealth Edison Company Docket No. 79-0214 (1980). Respondent claimed that the adjustment is necessary if it is to recover increased unit costs reasonably anticipated to occur during the first year the new rates are in effect.

Respondent presented evidence to show that its electric O&M expense per kwh sold has increased steadily from 0.33¢ per kwh in 1970 to 0.60¢ per kwh in 1979 and 0.65¢ per kwh in 1980, although remaining below the average for other utilities. Respondent's witnesses testified that O&M expense is forecasted to increase on a per unit basis to 0.75¢ per kwh for the twelve months ending June 30, 1982 due to high rates of inflation affecting this area of Respondent's operation and to slow energy sales growth. Respondent's evidence showed that disallowance of the adjustment in Respondent's last rate case would have resulted in a reduction in 1980 electric operating income of $4,943,838 and a reduction in the return on average equity from 13.4% to 12.5% for 1980.

Respondent's witness presented evidence to show specifically identifiable increases in payroll and other expenses accounting for $8,330,344 of the total proposed adjustment to expense of $13,652,841. The specifically identifiable increases include wage increases already received by Respondent's employees during 1980 and the first two months of 1981, additional wage and salary expense increases anticipated as a result of renegotiation of union contracts covering about 71% of Respondent's work force which expired June 30, 1981, and additional equipment rental expenses for a new 138 KV tie with Central Illinois Public Service Company.

The Staff witness testifying on behalf of the Commission's Accounts and Finance Department, although reversing Respondent's proposed adjustment, increased 1980 O&M expense by the annualized amount of payroll increases put into effect in 1980 and in the first two months of 1981. He also adjusted operating expenses for the effect of the postal rate increase from 15¢ to 18¢.

The Commission has reviewed all the data and information presented by Respondent in support of its proposed adjustment. The Commission is of the opinion that Respondent's forecasts reflect the after tax effect of the expenses as well as the Commission's past practices in this connection and therefore Respondent's proposed adjustment should be approved and utilized for purposes of this proceeding.

Proposed Adjustment to Invested Capital Tax Expense

Respondent proposed to adjust expenses for taxes other than income taxes to reflect the expense for state tax on invested capital which would be incurred based on the anticipated average capitalization structure of Respondent forecasted with rate increase at June 30, 1981 and June 30, 1982. The proposed adjustment to taxes other than income taxes was $2,942,000. The adjustment was calculated by applying the anticipated tax expense per kwh for the twelve months ending June 30, 1982 to 1980 kwh sales. Respondent presented evidence to show what the invested capital tax expense would have been had it been in effect for the years 1970-1979 based on the Company's capitalization in those years. The exhibit showed that this tax increased steadily on a total dollar and dollars per kwh basis. Respondent's Manager of Rates testified that since Respondent has detailed financing plans for the next several years, total capitalization, on which the tax is computed, can be predicted with reasonable accuracy.

Based on a review of Respondent's forecasted information including its financing plans, and the hypothetical effect of the invested capital tax applied to historical data as presented by Respondent, the Commission is of the opinion and finds that the proposed adjustment to invested capital tax expense is reasonable to enable Respondent to recover its cost of service during the first year rates

authorized by this order are in effect, and should be adopted for purposes of this proceeding.

Proposed Adjustment to Real Estate Tax Expense

Respondent proposed to adjust taxes other than income taxes by $166,000 to reflect real estate taxing levels anticipated during the twelve months ending June 30, 1982. The adjustment was calculated by applying the ratio, electric real estate taxes during the twelve months ending June 30, 1982 to electric plant in service and land held for future use during the corresponding period, to electric plant in service and land held for future use at December 31, 1979. Respondent's witness testified that the proposed adjustment reflects the increases in assessed valuations and taxing rates which Respondent will experience during the first full year the rates are in effect. The witness presented historical data to show that the ratio of real estate taxes to plant in service and land held for future use has increased steadily from 0.2838¢ per kwh in 1974 to 0.4386¢ per kwh in 1980, and it is forecasted to increase to 0.4572¢ per kwh during the twelve months ending June 30, 1982.

Based on a review of the historical and forecasted data presented by Respondent in support of the proposed adjustment, the Commission is of the opinion that the proposed adjustment to real estate tax expense is reasonable and should be adopted for purposes of this proceeding.

Additional Adjustments Proposed by Staff

Staff witnesses appearing on behalf of the Commission's Accounts and Finance Department proposed certain additional adjustments to 1980 historical data for ratemaking purposes. Respondent contested certain of these adjustments. The adjustments proposed by the Commission Staff witnesses are discussed below.

Adjustment for Advertising Expenses

Respondent presented evidence on its 1979 and 1980 advertising program and expenses which showed total 1980 electric utility advertising expenses of $365,536. A Staff witness who reviewed all advertisements used by Respondent in 1980, proposed to reduce advertising expense by $43,721 to reflect the expense associated with certain advertisements that he considered inappropriate for ratemaking purposes.

Respondent contested the adjustment with respect to two advertisements, each of which had a 1980 expense of $15,000, which the Staff witness testified should be eliminated from operating expense on the grounds that the advertisements contained material of a type for which expenses are not to be included in operating expenses for ratemaking purposes under the guidelines set forth in the Commission's Interim Order entered in Docket No. 79-0716 on November 5, 1980. Respondent claimed that since the two advertisements also contained information on conservation, for which expenses may be included for ratemaking purposes pursuant to the Interim Order in Docket No. 79-0716, 50% of the expense for these two advertisements should be included in operating expenses for ratemaking purposes.

The Commission believes that the rule against allocating the expenses for individual advertisements set forth in its Interim Order in Docket No. 79-0716 is appropriate and should be followed. Accordingly, the Commission adopts

the advertising expense adjustment proposed by Staff for ratemaking purposes.

Proposed Adjustment of Investment Tax Credit Amortization

A Staff witness testifying on behalf of the Commission's Accounts and Finance Department proposed to start, for ratemaking purposes, the amortization or flow back of the investment tax credit claimed by Respondent on certain "qualified progress expenditures" made in connection with construction work in progress at the time that such construction work in progress is included in rate base. The record showed that at December 31, 1980, qualified progress expenditures amounted to $869,624,000 on which Respondent has claimed and taken investment tax credits in the amount of $65,319,000.

Respondent contested this adjustment on the grounds that it is contrary to the Internal Revenue Code and applicable federal income tax rules and regulations which require that, for ratemaking purposes, investment tax credit may only be amortized or used to reduce cost of service over "the period of time actually used in computing the taxpayer's regulated depreciation expense for the property for which a credit is allowed." Respondent argued that inasmuch as the Staff did not propose that the Company advance or begin annual book depreciation charges at a point in time earlier than the in-service date of the plant under construction, a proposed amortization period beginning three years earlier, when construction work in progress is included in rate base, would be directly contrary to applicable tax rules and regulations.

Respondent further argued that adoption of the proposed adjustment would place in jeopardy the propriety of all investment tax credits claimed by Respondent for all past years not closed by the statute of limitations and for all future years, an amount of credits greatly exceeding the $65,319,000 of tax credits on "qualified progress expenditures" previously claimed by Respondent.

The Commission has reviewed the proposed adjustment recommended by Staff and the statutory provisions, regulations and legislative history cited by Respondent. The Commission is not persuaded that the adoption of the adjustment proposed by Staff would result in a better matching of rate revenues to the flow back of investment tax credits on qualified progress expenditures associated with construction work in progress. Therefore, the staff proposed adjustment should not be adopted.

Adjustment of Return to Reflect Pro Forma Effect of Uniform Fuel Adjustment Clause

A Staff witness appearing on behalf of the Accounts and Finance Department of the Commission applied the Uniform Fuel Adjustment Clause ("UFAC"), which Respondent proposes to adopt effective with the date of this Order, to 1980 fuel costs and fuel costs revenues pro forma, and concluded that there would have been an over-recovery of fuel costs had the UFAC been in effect during 1980. Inasmuch as the UFAC contains provisions for refunding any over-recovery of fuel costs, the witness proposed an adjustment to return to eliminate the over-recovery from test year return. The adjustment would reduce test year return by $654,000 to provide a better matching of test year revenues and fuel costs. The Commission is of the opinion that the proposed adjustment should not be utilized for purposes of this proceeding since General Order 211 embodying the UFAC has not been adopted.

Based on all the foregoing considerations, the Commission is of the opinion and finds that electric operating income, with adjustments, for the test year 1980 which should be utilized for purposes of this proceeding is as follows:

ELECTRIC OPERATING INCOME STATEMENT, WITH ADJUSTMENTS
TWELVE MONTHS ENDED DECEMBER 31, 1980

Item	Amount (000)
Operating revenues	$523,470
Operating expenses	
Fuel for electric plants	240,600
Purchased Power net	(33,920)
Operation and maintenance	108,440
Depreciation and amortization	48,050
Taxes other than income taxes	42,350
Federal income taxes-current	4,820
State income taxes-current	4,160
Provision for deferred income taxes	21,100
Income taxes deferred in prior years	(3,850)
Investment tax credit deferred-net	22,160
Jurisdictional allocation	(26,260)
Total operating expenses	427,650
Operating Income	$ 95,820

Rate of Return Based on 1980 Test Year

Based on the original cost and fair value rate bases and operating income statement for the 1980 test year adopted by the Commission for purposes of this proceeding, Respondent's pro forma return for the 1980 test year at present rates is 6.04% on fair value rate base and 7.49% on net original cost rate base.

CONSTRUCTION WORK IN PROGRESS

Much of the evidence presented in this case related to Respondent's proposal to include in rate base an additional $412,936,000 of construction work in progress resulting in a total amount of construction work in progress ("CWIP") in rate base of $510,000,000, and to cease capitalization of AFUDC on this amount.

The Commission has in previous cases involving proposals to include CWIP in rate base, including the last two Illinois Power Company rate orders, Docket Nos. 76-0435 (June 15, 1977) and 79-0071 (November 28, 1979), developed and applied a standard for determining when CWIP may appropriately be included in rate base. The Commission stated its standard as follows in its Order in Docket No. 79-0071 (at p.37):

> "The Commission views the investment of funds in CWIP as used and useful to the benefit of the customer which may be included as a component of the rate base when, pursuant to a certificate of convenience and necessity granted by the Commission for construction of such a plant, the investment grows to a point where its significance is so great that it could impair financing. To what extent such investment, if any, should be included in the rate base for a particular public utility must, how-

ever, be determined by the specific circumstances in each rate proceeding and will be considered by the Commission on a case-by-case basis."

In support of its proposal to include an additional amount of CWIP in rate base, Respondent presented evidence on the size of its investment in CWIP in relation to its total capitalization; the impact of its construction program on its ability to raise additional capital as measured by statistics such as interest coverages, internal cash generation as a percentage of additions to plant, and AFUDC as a percent of earnings; and the effect of Respondent's large construction program on investor attitudes towards Respondent's securities. Respondent also offered evidence on the comparative revenue requirements resulting from inclusion of an amount of CWIP in rate base as opposed to capitalization of AFUDC on that amount, and on other benefits of including CWIP in rate base from the point of view of both the utility and the ratepayer.

The record shows that at December 31, 1980, Respondent's investment in CWIP was $927,115,748 constituting approximately 46% of the total permanent capitalization of the Company at that date. Respondent's forecasts showed that its investment in construction work in progress will exceed $1 billion by June 30, 1981 and would constitute over 53% of total capitalization at December 31, 1981 and over 57% of total capitalization by June 30, 1982.

A witness on behalf of Respondent testified on the effect of Respondent's large balance of electric construction work in progress on Respondent's financial condition and ability to raise capital. The witness testified that the lack of a current cash return on a significant portion of Respondent's invested capital has resulted in deterioration of its ability to service adequately its outstanding capital and to raise additional capital for its current construction program.

Due to the disparity between total assets and assets producing a cash return, Respondent's cash earnings from operations are insufficient to pay fixed charges and a reasonable common dividend. The gap between operating income after fixed charges and common dividend requirements has grown from $9.8 million in 1977 to $36.4 million in 1980. This requires Respondent to raise additional capital in order to have the funds needed to service existing capital, which the witness testified dilutes earnings and the value of present equity holders' investment and is viewed as a sign of a financially unsound enterprise by prospective investors, since a healthy firm generates sufficient income from its operations to service its outstanding capital without having to sell additional securities for this purpose.

Respondent's witness stated that continued issuance of first mortgage bonds and preferred stock to finance construction which earns no current cash return, plus the need to sell securities during periods of high inflation and interest rates, has caused coverage ratios specified in Respondent's mortgage indenture and incorporation documents to fall to near the levels at which no additional bonds or preferred stock can be issued. Protective provisions in Respondent's mortgage indenture restrict the issuance of additional first mortgage bonds unless earnings from operations are two times interest requirements on the bonds outstanding plus those proposed to be issued. Respondent's evidence showed that its mortgage interest coverage ratio at

December 31, 1980 was 2.45 but that the coverage is forecasted to fall to 1.65 at December 31, 1981 and to 1.37 at June 30, 1982.

Respondent's witness also testified that as the balance of construction work in progress increases, Respondent's internal generation of cash for construction requirements declines, due in substantial part to the fact that current depreciation, which represents cash flow, is based on the original cost of plant in service that was built in the past at costs much lower than the costs of facilities currently being installed, and is therefore insufficient to fund current construction. Retained earnings are also inadequate for this purpose. Respondent's internal cash generation as a percentage of additions to utility plant has declined from 61.9% in 1975 to 24% in 1980 and is forecast to decline to negative 1.8% for the 12 months ending June 30, 1982. Reduced internal cash generation of construction requirements increases Respondent's reliance on the external capital markets, which at the present time are characterized by extremely high interest rates compared to historical levels.

Respondent's witness testified that if CWIP is included in rate base, Respondent obtains additional cash return which reduces its need to issue additional securities to obtain funds to pay interest and dividends. In addition, interest coverage ratios are improved due to the greater cash earnings and reduced interest requirements since fewer securities are issued.

A vice president of an investment firm testified on the effect of Respondent's large construction program on investor attitudes toward Respondent's securities. He stated that while investor attitudes are relatively favorable toward Respondent's senior securities because its security ratings have not declined from AA, a decline in credit standing and thus in investor attitudes toward Respondent's senior securities is likely if Respondent's financial indicators are not maintained at necessary levels during the next several years. He further testified that, with respect to Respondent's common stock, investor attitudes are neutral to negative because earnings per share have not grown in recent years and have declined in real terms; dividend growth has been negative in real terms; stock price appreciation has been inadequate; and the quality of earnings has declined as the AFUDC portion of Respondent's earnings has risen.

The evidence showed that AFUDC as a percentage of Respondent's earnings per share has increased from 15.1% in 1975 to 54.2% in 1980 and is forecast to be 82.2% for 1981 and 93.1% for the year ending June 30, 1982. Respondent's witness particularly emphasized that investors react negatively to earnings in the form of AFUDC because they recognize that it is not cash and that the utility may have to sell additional securities simply to have the cash necessary to pay its common dividends, thereby reducing the value of existing investors' investment in the Company. The witness testified that unless Respondent's cash flow is improved and the AFUDC component of its earnings reduced, investor attitudes towards its common securities will deteriorate and investors will not be attracted to its new securities.

Respondent's witnesses also presented evidence indicating that Respondent's large investment in CWIP may result in its securities being downgraded by security rating agencies. The record shows that these agencies rely on numerous factors which include financial indicators of cash flow, internal cash generation and cash coverage of fixed charges

including interest coverage before income taxes, excluding AFUDC; internal cash generation as a percentage of additions to utility plant; AFUDC as a percentage of earnings applicable to common equity; debt ratio; cash flow to long term debt and internal cash generation as a percentage of debt.

Data presented by witnesses on behalf of Respondent and witnesses on behalf of the Commission Staff indicated that Respondent is experiencing a serious decline in these measures of financial integrity. Respondent's evidence showed that if its senior securities were downgraded, its ability to raise capital would be seriously affected and its cost of capital would increase, since a substantial spread usually exists between the cost of newly-issued AA rated public utility bonds and single A rated public utility bonds; some institutional investors cannot or will not purchase utility bonds rated lower than AA; and utilities with lower quality bond ratings are in a weaker position to compete for capital against the U.S. Government whose debt securities are viewed as having very little risk and recently have carried very high interest rates as well.

A Staff witness from the Commission's Policy Analysis and Research Division also testified on the effects of a large construction program on Respondent. He observed that a construction project which grows to a considerable percentage of operating rate base places a considerable strain on the utility's financial position and that the AFUDC treatment of construction costs places considerable pressure on its financing requirements. The ultimate impact in many cases is an increase in the cost of capital and construction costs due to deterioration in the utility's financial condition.

Inclusion of construction work in progress in rate base helps to maintain the financial integrity of the utility and may reduce capital costs and cost increases resulting from construction delays. The Staff witness presented exhibits displaying results of computer simulation runs showing financial ratios for Respondent for 1981-1985 if all AFUDC were capitalized and if various amounts of construction work in progress were included in rate base at a lower rate of return than that allowed plant in service. These exhibits showed Respondent would experience improved financial ratios if construction work in progress were included in rate base, even at a lower rate of return than that applied to operating plant.

Respondent addressed, in its evidence, the extent to which including CWIP in rate base balances ratepayer and stockholder interests. Respondent presented evidence to show that during the last several years in which Respondent has been constructing and financing Clinton Unit No. 1, Respondent's stockholders have experienced a decline in the market price of their stock, stagnant earnings and dividends which have actually declined in real terms, declining interest coverages, and a drop in market price to book value ratio. Respondent also showed that at June 30, 1981, only about 9% of the total investment in CWIP would be included in rate base and that Respondent's proposed amount of $510 million to be included in rate base would represent only about 47% of the total construction work in progress at June 30, 1981.

Respondent's witnesses addressed certain benefits to ratepayers of including an amount of CWIP in rate base. It was pointed out that ratepayers have benefitted from Respondent's low rates which have resulted in part from Respondent's ability to maintain satisfactory financial integrity that has enabled it to raise capital on favorable terms. Respondent stated that inclusion of CWIP in rate base will

help Respondent to maintain a satisfactory level of financial integrity and thus contribute to lower rates.

One of Respondent's witnesses testified that ratepayers benefit from inclusion of CWIP in rate base because they receive assurances that electric energy supplies will continue to be adequate; they receive the benefit of lower current rates to the extent the utility's current capital costs are lowered due to the inclusion of CWIP in rate base; and most present customers will receive service from the new plant and benefit from the lower revenue requirements when it goes into service. Even current customers who never receive service from the plant may be benefitted if the value of their property is increased by the prospect of effect, lower cost service from the new plant.

And economists testifying on behalf of respondent presented exhibits to show that total revenue requirements over the life of the plant will be less if CWIP is included in rate base than if CWIP is excluded, and that, on a present value basis, the revenue requirement streams under the two alternatives are equal.

The analysis was presented by Respondent using both embedded capital cost and incremental capital cost data. Using embedded capital cost for the calculation, total revenue requirements were shown to be lower by $233 million over the life of the plant if $510 million of construction work in progress is included in rate base. Using incremental capital cost for the analysis, total revenue requirements over the life of the plant were shown to be $272 million lower if $510 million of construction work in progress is included in rate base.

The difference in revenue requirements is due primarily to the fact that if all AFUDC is capitalized, the final installed cost of the project is greater, requiring greater depreciation allowances and return requirements over the service life of the plant. Respondent's witness testified that other factors not explicitly included in his analysis would tend to make the alternative of excluding all construction work in progress from rate base even more expensive. These additional factors include the incidence of gross revenue taxes and the Illinois invested capital tax, and future increases in the cost of capital which would result in higher total dollar return requirements on the larger rate base which the utility will have if all AFUDC is capitalized.

Respondent's witness as well as a member of the Commission's Policy Analysis and Research Division testified that if a utility has insufficient cash flow to support current construction, it may defer completion of its current construction program resulting in higher costs in the long run.

A Staff witness from the Accounts and Finance Department of the Commission testified that inclusion of CWIP improves the utility's ability to fund construction activities through internal cash generation and thereby reduces the utility's dependence on the external capital markets. This reduces the need to sell additional securities at current higher capital costs and thus benefits ratepayers because it keeps embedded costs of capital, which are used to determine the rate of return applied to rate base in setting rates, at lower levels than would otherwise be the case.

An accountant on the staff of the California Public Utilities Commission testified on behalf of CCS. The witness presented a forecast to show that Respondent's internal

cash generation would improve substantially after Clinton Unit No. 1 is placed in rate base. He testified that inclusion of CWIP in rate base, resulting in higher rates until the plant is in service, in return for reduced cost of service and rates during the 30-year life of the plant, would be neither equitable nor a proper matching of costs and benefits for different generations of ratepayers. The witness quantified the revenue requirements associated with $510 million of CWIP and with the corresponding amount of AFUDC over a 30-year depreciable plant life, and showed them to be equal on a present value basis when discounted using the capitalization or AFUDC rate. He concluded that Respondent's proposal to include CWIP could not be justified from the standpoint of ratepayers or of need for internal cash generation.

A regulatory consultant appearing on behalf of the Department of Defense ("DOD") recommended that CWIP should not be included in rate base. He based his opinion on the following factors: (1) failure to capitalize the return requirements on investment in construction work in progress during the construction period would not be in conformance with the Financial Accounting Standards Board's "Statement of Financial Accounting Standards No. 34, Capitalization of Interest Costs" ("FASB No. 34"); (2) inclusion of CWIP in rate base would not be in conformance with the regulatory principle that customers should only be charged for plant used and useful in providing their service; (3) Respondent is not in sufficiently poor financial condition to justify inclusion of CWIP in rate base.

The DOD witness also contended that Respondent's mortgage indenture permits inclusion of AFUDC as income in computing interest coverage for purposes of determining whether Respondent may issue additional first mortgage bonds. In support of his recommendation the witness offered a study entitled "Market Indicator Study" dated March 1979 in which he analyzed data on earnings/price ratios of three Maryland utilities, one of which includes construction work in progress in rate base and two of which do not, and expressed the following conclusion: "The observed variations in the earnings/price ratios of the compared Maryland companies, Potomac Edison Company and Delmarva Power and Light Company, were not statistically significant at the ninety-five percent confidence level and do not support the statement frequently made that market investors differentiate between the capitalized Allowance for Funds Used During Construction income and operating income."

The Commission is of the opinion that the considerations offered by the DOD witness do not support his recommendation. With respect to his comments concerning FASB No. 34, the record reflects that the Addendum to Accounting Principles Board Opinion No. 2 permits departures from accounting principles for regulated firms in the context of the ratemaking process. Further, FASB No. 34 explicitly excludes capitalization of equity costs and permits capitalization of incremental interest costs. Application of FASB No. 34 could place Respondent in direct violation of the FERC formula for computing AFUDC, which calls for use of embedded debt costs and of equity costs.

With respect to the DOD witnesses' views on construction work in progress as not used and useful, the Commission, as previously expressed herein and in prior orders, views a utility's investment in construction work in progress as used and useful to the benefit of current ratepayers under the conditions heretofore set forth. In connection with the DOD witnesses' views concerning the inte-

rest coverage test of Respondent's Mortgage and Deed of Trust dated November 1, 1943, the record shows that the mortgage specifies a calculation of net earnings for determination of interest coverage based on "operating revenues" and "net non-operating revenues," and does not mention AFUDC in this connection.

In regard to the DOD witnesses' "Market Indicator Study" the Commission views it as interesting but of limited use for purposes of this proceeding because of its narrow scope and lack of comparability to the instant case. The record shows that because two of the three Maryland utilities analyzed by the witness are subsidiaries of holding companies, he based his study on earnings per share data for the holding companies. One of the holding companies obtains only about 22% of its revenues from retail operations in Maryland while the other operates in five states and receives only about 18% of its revenues from retail operations in Maryland. The third utility operates in these jurisdictions and less than 50% of its revenues are obtained from operations in Maryland. Further, the record shows that the percentage of AFUDC to earnings experienced by these utilities during the period studied did not reach the levels being experienced by Respondent; nor was data presented to indicate that the percentage of CWIP to net plant experienced by these utilities approached the levels which Respondent is experiencing.

Respondent presented evidence in support of its proposal to include the specific amount of $510 million of CWIP in rate base. It was noted that the Commission has heretofore permitted an amount of construction work in progress to be included in Respondent's rate base equal to approximately 10% of net original cost rate base. The proposed amount of $510 million would constitute approximately 36% of the proposed original cost rate base at December 31, 1980. Respondent claimed that it requires inclusion of more CWIP than an amount equal to approximately 10% of rate base in order to maintain its financial integrity and ability to raise capital on reasonable terms.

Respondent's Vice President presented forecasted data comparing financial ratios of interest coverage excluding AFUDC, internal cash generation as percent of additions to utility plant, and AFUDC as percent of earnings (1) if no rate increase were granted, (2) if a rate increase based on an amount of CWIP equal to 10% of rate base were granted, and (3) if the full requested rate increase based on inclusion of $510 million of CWIP in rate base were granted.

A similar presentation was made by the Assistant Director of OCS for years 1980-1984 using forecasted data prepared by Respondent. These comparisons indicated that while Clinton Unit No. 1 is under construction, Respondent's financial position relating to cash coverages, internal cash generation and cash flow as measured by these statistics would not be substantially improved by a rate increase which only reflected inclusion of CWIP equal to 10% of rate base.

A Staff witness appearing on behalf of the Accounts and Finance Department of the Commission presented forecasted financial and operating results for 1981 for Respondent based on a number of hypotheses which combined various assumptions as to amounts of construction work in progress included in rate base ranging from $97.06 million to $600 million with various rates of return ranging from 10.22% to 10.97%. The witness' presentation was developed using computer modeling techniques available to the Commission Staff.

A review of the detailed presentation made by this witness shows that Respondent's financial position relating to cash coverages, internal cash generation and cash flow is noticeably improved as greater amounts of CWIP are included in rate base.

A witness testifying on behalf of Respondent stated that if the amount of CWIP included in rate base was limited to 10%, Respondent would fall far short of maintaining its financial integrity, and its credit ratings would be in jeopardy. The witness stated that under this limitation, Respondent would not be able to generate sufficient cash to improve the three important financial indicators of interest coverage excluding AFUDC, internal cash generation as a percentage of additions to utility plant, and AFUDC as a percentage of earnings per share. There would be no real improvement in Respondent's cash flow.

The Assistant Director of OCS offered testimony on increases in the cost and construction schedule of Clinton Unit No. 1 as it related to the proposal to include CWIP in rate base. The witness presented evidence showing that the estimated final cost has increased from $551,750,000 in 1974 to $1,732,981,000 in 1980, and that the scheduled commercial operation date has changed from June 1980 to September 1983.

The OCS witness attributed cost increases and schedule delays to changes in estimates of the scope of work to be accomplished as conceptual designs were developed into detailed designs; use of assumed labor productivity rates "which have proven unattainable;" and Respondent's failure to anticipate regulatory changes or refinements promulgated by the Nuclear Regulatory Commission. He characterized the industry experience in estimating nuclear construction costs as "uniformly dismal." The witness pointed out that delays in commercial operation result in increased construction cost escalation and AFUDC costs.

The OCS witness stated that Respondent should be deemed solely responsible for increases in the cost of Clinton Unit No. 1 because Respondent elected to construct the plant using a developing technology which is capital intensive and requires a long lead time. He also stated that any comparison of cost increases for Clinton Unit No. 1 to the industry experience should include all boiling water reactors (BWR) and pressurized water reactors (PWR) under construction.

An officer of Respondent presented evidence on recent cost increases and construction schedule changes for Clinton Unit No. 1. He sponsored evidence which broke out cost increases as between direct construction costs, indirect expenses and AFUDC, and further explained the increased costs through a total of 78 line items. The witness identified changing regulatory requirements, including new and amended regulations, new engineering interpretations of prior regulations, and stricter application of quality assurance requirements, plus increases in the AFUDC rate to reflect higher current capital costs, as the major reasons for cost increases.

A Staff witness from the Policy Analysis and Research Division of the Commission presented testimony and exhibits relating to a comparison of the estimated final cost and scheduled in-service date for Clinton Unit No. 1 to those for all other one-unit nuclear reactors, both BWR and PWR, under construction. The witness' findings based on his study were as follows: (1) the current estimated cost for Clinton Unit No. 1 compares favorably with those for other

unfinished BWRs and PWRs; (2) the estimated cost for Clinton Unit No. 1 is compatible with those for all other BWRs; (3) the estimated cost for Clinton Unit No. 1 lies within the 95 percentage confidence level for the different groups of one-unit reactors identified; (4) the length of delay in the scheduled in-service date for Clinton Unit No. 1 since the date of issuance of the construction permit is below the mean level for all of the reactors; (5) the increased estimated cost for Clinton Unit No. 1, starting in April 1979, has risen at one-half the average rate for all BWRs; (6) the wide range of costs among reactors can be explained systematically by many factors, some of which would have an adverse effect on the cost for Clinton; (7) the estimated length of construction and testing for Clinton Unit No. 1 may partly explain the reasonableness of its current estimated cost. The witnesses' exhibits showed a current (December 1980) estimated cost for Clinton Unit No. 1 of $1,824 per KW compared to a mean of $1,917 per KW for all BWRs, $2,310 per KW for all one-unit BWRs, $1,678 per KW for all PWRs, $1,815 per KW for all plants (BWRs and PWRs), and $2,279 per KW for all one-unit reactors.

The Commission has reviewed the evidence presented by Respondent, OCS and the Commission Staff with respect to the current estimated final cost and scheduled in-service date of Clinton Unit No. 1, and the increases in estimated final cost and delays in commercial operation date which have occurred. The evidence presented of record in this proceeding indicates that although cost increases for this project have been substantial, the cost increases and the estimated final cost are comparable to the industry experience. The only conclusion which can be drawn from the record is that Respondent has been subject to the same factors which have affected the entire electric utility industry.

In Docket No. 79-0071, the Commission decided to initiate an investigation to establish incentives for cost control in the Clinton Unit No. 1 project, including investigation of the need for an audit of management and construction practices at this project and the development of an incentive scheme to reward or penalize Respondent for superior or poor cost control. This investigation, which is currently being conducted in Docket No. 80-0167, was initiated because the Commission was of the opinion that the evaluation of such matters is beyond the scope of a rate case proceeding and should be conducted in a separate inquiry. To the extent the evidence received in this case is relevant to the inquiry being conducted in Docket No. 80-0167 it should be considered in that proceeding.

The Commission has reviewed and analyzed all evidence presented by witnesses for Respondent, Staff and Intervenors in this case relevant to the issue of whether and to what extent construction work in progress should be included in Respondent's rate base. The Commission has reviewed the historical and forecasted financial statistics presented by Respondent, Staff and Intervenors; the comparisons made by witnesses for Respondent, Staff and Intervenors between Respondent's historical and forecasted financial performance and that of other utilities having various credit ratings; information in the record on the factors considered by security rating agencies and the factors which influence investor attitudes towards Respondent's securities; data on the size of Respondent's construction program in relation to its total capitalization; evidence on the comparative revenue requirements resulting from inclusion or exclusion of CWIP in rate base and on other asserted benefits or burdens to the ratepayer and stockholder of inclusion or

exclusion of CWIP; data on Respondent's construction and financing needs; the current and foreseeable state of the capital markets and Respondent's present ability to raise capital, including its present ability to sell additional first mortgage bonds and preferred stock subject to the coverage requirements of its mortgage indenture and Articles of Incorporation; opinion testimony on Respondent's financial condition and on the impact of its large balance of CWIP on its ability to maintain financial integrity and to raise capital; and evidence of Respondent's current and proposed rate levels as compared to those in effect for other Illinois utilities. Based on all this evidence, the Commission is of the opinion and finds that the size of Respondent's investment in construction work in progress on which it is presently earning no cash return is so great that it is impairing and will continue to impair Respondent's ability to raise capital to continue its construction program unless Respondent is allowed to earn a cash return on a larger portion of that investment.

The Commission notes the following factors of record in support of its conclusion: (1) Respondent is approaching the limits of issuance of additional first mortgage bonds and preferred stock because it will not be able to satisfy the interest coverage test of its mortgage indenture and the dividend coverage requirement of its Articles of Incorporation. (2) Financial ratios indicating interest coverage, internal cash generation and quality of earnings are deteriorating to a point where Respondent's security ratings are in jeopardy; downgradings would raise the cost of capital to Respondent and reduce the availability of capital in the external markets. (3) Respondent's deteriorating internal cash generation is reducing its ability to finance construction from internal sources and increasing its dependence on the external capital markets at a time of high capital costs. (4) Respondent's deteriorating financial integrity resulting from the burden of its large construction program is negatively affecting investor attitudes towards Respondent's securities as reflected by Respondent's stock price which is substantially below book value thereby impairing Respondent's ability to raise capital through the sale of common stock. (5) Continued difficulty in raising capital including the possible prohibition on issuance of additional first mortgage bonds and preferred stock threatens Respondent's ability to raise capital needed to complete construction of Clinton Unit No. 1 and therefore can result in delay in the completion of the unit which would increase its ultimate total cost.

The amount of construction work in progress which must be included in rate base in order to maintain Respondent's financial integrity and ability to raise capital while maintaining reasonable current rate levels is not susceptible of being exactly determined through a precise mathematical formula. Application of judgment by the Commission based on full consideration of all the factors heretofore cited including the effect of inclusion of any amount of CWIP on ratepayers as measured by the resulting rate levels is necessary to this determination. Based on consideration of all the evidence, the Commission is of the opinion and finds that $375 million of construction work in progress should be included in Respondent's rate base.

In making this determination the Commission relies particularly on the evidence presented by Respondent and Staff which shows that Respondent's financial statistics relating to internal cash generation and cash flow, which are the principal measurements of the effect of its large construction program on the ability to raise capital, will not be

significantly improved or even necessarily maintained at current levels if any substantially lower amount of CWIP is included in rate base. The Commission also relies, with respect to the effect of this determination on the ratepayer, on the evidence which shows that total revenue requirements over the life of Clinton Unit No. 1 will be lower by approximately $397 million for each $200 million of CWIP included in rate base; and on the fact that, even with this amount of construction work in progress included in rate base, Respondent's rates, particularly its residential rates, will continue to be among the lowest available to ratepayers in this state.

Proposal to Apply a Lower Rate of Return to Construction Work in Progress Included in Rate Base

A Staff witness from the Policy Analysis and Research Division of the Commission, who testified generally in favor of inclusion of CWIP in rate base, recommended that CWIP in progress should be included in rate base at a lower allowed rate of return than that applicable to plant in service. The witness did not attempt to quantify the appropriate return differential between operating plant and CWIP. The witness based his recommendation principally on three incentives to the utility which he testified would result from use of his proposed methodology: (1) The utility would be forced to earn its return rather than having it automatically credited as under the AFUDC treatment; (2) the utility would receive an incentive to avoid delays in construction since the firm will be allowed a higher return on its investment once the project is completed and on line; and (3) any delays and cost increases in the project which require additional financing at higher current marginal costs of capital result in a reduction of the firm's earnings due to regulatory lag.

An economist testifying on behalf of Respondent commented on the three incentives referred to by the Staff witness. Respondent's witness testified, with respect to the first incentive, that it is the inclusion of CWIP in rate base, not the allowance of a variable return on CWIP, that requires the utility to earn its return. With regard to the second incentive, the Company witness pointed out that the variable return to CWIP approach must not be applied in a manner that results in the overall rate of return allowed the utility being below its cost of capital, since to do so would be inequitable to providers of capital and could result in a loss of the benefits of including CWIP in rate base and lead to higher costs for ratepayers. In other words, this particular incentive can exist only if the utility is either restricted from earning its overall cost of capital during the construction period or allowed to earn in excess of its cost of capital during the operational period. In connection with the third incentive, Respondent's witness testified that the incentive arose from the inclusion of CWIP in rate base, not from the allowance of a variable rate of return on CWIP. Respondent's witness summarized his views on the Staff witness' proposal by stating that, if the proposal is adopted, it must not be applied in a manner which denies Respondent the opportunity to earn its overall cost of capital.

The Commission has reviewed the basis for the proposal advanced by the Staff witness, including the supporting computer analyses, and the rebuttal testimony offered by Respondent. The record suggests that at least certain of the incentives identified in connection with the "variable return to CWIP" approach exist independently of the rate of return applied to CWIP included in rate base. It also

appears that the variable return approach, if utilized, must be structured in such a way as to insure the utility an opportunity to earn its cost of capital, since, if this is not done, the benefits of including CWIP in rate base enhancing Respondent's ability to raise capital on reasonable terms may be reduced or lost. Since implementation of the variable return approach in such a way as to insure Respondent an opportunity to earn its cost of capital requires a precise determination of the appropriate differential between rate of return allowed on operating plant and rate of return allowed on construction work in progress, and there is no evidence in the record to quantify an appropriate differential, this approach should be deferred at this time and explored further.

The Commission is in the process of investigating the possible incentives for control of future costs at Respondent's Clinton Unit No. 1 construction project (Docket No. 80-0167), and the Staff witnesses' proposal is being evaluated in that investigation. Based on the present record before it in this docket, however, the Commission is of the opinion that the "variable return to CWIP" approach should not be utilized for purposes of this proceeding.

RATE OF RETURN

Respondent proposes that it be allowed a rate of return of 12.07% on 1980 original cost rate base. Respondent submitted evidence which it claims shows its cost of capital to be 11.30% during the first year rates approved by this Order are in effect. Respondent also proposes an attrition factor of 0.77% to be included in determining the fair rate of return in order to enable Respondent to earn its 11.30% claimed cost of capital during the first year the rates are in effect.

Respondent's Vice President presented evidence showing the capital structure and cost rates used to determine Respondent's cost of capital during the twelve months ending June 30, 1982. The witness testified that the proposed capital structure and embedded costs took into account financings planned by Respondent during the twelve months ending June 30, 1982 if the full requested rate increase is granted. The witnesses' proposed capital structure and cost of capital calculation shown on his exhibit were as follows:

Class of Security	Capitalization Ratio	Cost	Weighted Cost
Long Term Debt	47.94%	8.95%	4.29%
Preferred Stock	12.19	8.46	1.03
Common Stock Equity	39.87	15.00	5.98
			11.30%

Respondent's evidence also showed that at December 31, 1980 its capital structure consisted of 49.87% long term debt, 12.56% preferred stock and 37.57% common stock equity, and that its embedded cost of long term debt and preferred stock capital at that date were, respectively, 8.39% and 7.97%.

In support of its proposed cost of capital, Respondent presented the testimony of an economic expert in the field of public utility regulation including cost of capital. This witness expressed his opinion that the opportunity cost of equity capital for Respondent during the twelve months ending June 30, 1982 is approximately 15.0%. He also testified that the appropriate period for determining Respondent's capital structure and cost of senior capital for

purposes of determining the overall cost of capital is the first full year new rate levels will be in effect. The witness further testified that use of the forecasted capital structure as proposed by Respondent would be appropriate since it would represent a move toward more equity and less debt which movement is strongly supported by Respondent's present and projected financial condition and financial requirements.

Respondent's witness identified the three principle economic criteria for determining the cost of capital for a public utility, namely, maintenance of financial integrity, ability to attract new capital on reasonable terms, and ability to provide returns to the equity holder commensurate with returns on alternative investment opportunities. In determining the earnings requirement on Respondent's common stock, the witness relied principally on the comparable earnings or opportunity cost standard which focuses on what the investor's capital can earn in various alternative investments of comparable risk to Respondent's common stock.

In support of his analyses, Respondent's witness presented data on current and foreseeable economic trends and conditions and specific analyses pertaining to the cost of common equity to Respondent. The witness presented data showing that general inflation in the economy and money costs in the capital markets have been very high in recent years, which has resulted in increases in the embedded costs of senior capital to Respondent and other utilities and in sharp declines in coverage ratios for Respondent and other utilities; and has caused investors to switch investments from utility stocks to other high-yielding investments such as long-term U.S. Government bonds or tax free municipal bonds as the effective yields on these alternative investments have approached or exceeded the yields on utility stocks.

According to Respondent's witness, in 1980, long-term U.S. Government bonds carried a yield of 11.46% and high-grade tax-free municipal bonds carried a yield of 8.51%. He also showed that utility stocks in general and Respondent's common stock in particular have declined substantially in market price and in market price adjusted for inflation as compared to industrial common stocks; and that Respondent's dividend per share has declined substantially in inflation-adjusted terms while its dividend payout ratio has remained at a level (80% or greater) substantially higher than payout ratios of industrial firms. The witness concluded that for the foreseeable future: (1) economic trends and conditions which have adversely affected utility financial integrity, particularly high inflation, will continue; (2) embedded costs of senior capital will continue to rise; (3) difficulties in maintaining adequate coverages will continue; (4) utility common stock prices will be negatively affected; (5) investors will view inflation as a major risk factor for utilities; and (6) capital costs for public utilities will remain high.

In selecting investments of comparable risk to Respondent's common stock, Respondent's witness focused on financial risk, which is the risk imposed on a firm's common equity holders by management's decision to issue different types of securities. He testified that firms with higher business risk usually finance with lower debt ratios while firms with lower business risk introduce greater amounts of debt into their capital structures. As utilities have experienced higher business risk since the late 1960s, they have been perceived as having increased financial risk due to their highly leveraged capital structures.

Respondent's witness found that the business risk, and consequently the financial risk, of utilities has increased relative to that of industrial enterprises in recent years due to high annual rates of inflation, rapidly increasing fuel costs, rising embedded capital costs and declining coverage ratios, stagnant earnings per share growth, increased dependence by utilities on external funds to finance construction, and growing resistence to further rate increases. Based on a comparison of price-earnings ratios and of market price to book value ratios of Respondent and other utilities to those of industrial firms as measured by Standard & Poor's Index ("S&P") of 400 Industrials, which comparison provides a measure of investor perceptions of relative risk among investments, the witness concluded that the financial risk of utilities in general and Respondent in particular is currently comparable if not higher than the financial risk of the average industrial firm. The witness therefore compared, to determine the opportunity cost of capital, the return on Respondent's common equity to that earned by S&P 400 Industrials in recent years. Industrial firms earned 14.6% and 16.5% on equity in 1978 and 1979, respectively, while Respondent earned 12.60% and 12.16% in those years.

Based on his analysis, Respondent's witness concluded that the opportunity cost of equity capital for Respondent is approximately 15% for the twelve months ending June 30, 1982. He also observed in support of his analysis that since new long term debt would cost Respondent 12% or more, a 15% return on Respondent's common equity would represent a spread of only 3.00 percentage points or less over the cost of senior capital, which the record indicates is equal to or slightly less than the spread between newly-issued AA utility bonds and return earned by Respondent on average common equity in the years 1975-1980.

An economic expert appearing on behalf of the Industrial Power Users also offered evidence on the cost of capital to Respondent. The witness presented calculations which indicated a range of the estimated cost of equity capital for twelve utilities which he stated were comparable to Respondent of 13.88% to 14.31% and for Respondent specifically, 13.68% to 14.13%. He stated his opinion that 13.70% is a reasonable cost of common equity for Respondent. Using the capital structure and embedded cost rates of senior capital at December 31, 1980, and a 13.70% return on common equity, the witness showed a weighted average cost of total capital at December 31, 1980 of 10.33%.

This witness relied principally on the discounted cash flow method for determining cost of equity capital. He also presented a supplemental analysis in which he calculated the spread between yields on AA utility bonds and rate of return earned on year-end common stock equity by Moody's 24 Utilities over the ten year period 1970-1979, which he added to the current yield on bonds of AA utilities. The Industrial Power Users' witness calculated an average spread for the ten year period of 2.16% and represented the current yield on AA utility bonds by the average yield on Standard & Poor's AA utility bonds for the 15 months ended September 30, 1980, which he calculated to be 11.31%.

The Industrial Power Users' witness presented a calculation of the cost of equity capital to Respondent using the discounted cash flow ("DCF") method, under which the cost of equity capital is stated to be equal to the present common stock dividend yield plus anticipated growth rate in dividends per share. For his DCF analysis, the witness utilized a dividend yield represented by the average dividend and average market price for the 34 months ended October

31, 1980. To represent anticipated growth in dividends per share, he used annual growth rates in book value per share over the five year period 1975-1979 (2.47%) and the ten year period 1970-1979 (2.92%).

The Commission notes that while the discounted cash flow approach seeks to calculate cost of capital through a mathematical formula, the selection of the time periods to be used for determining dividend yield and growth rate is subject to considerable judgment. The Commission is of the opinion, based on the high interest rates and inflation which have prevailed in recent years, that if the DCF method is to be utilized, it should reflect greater consideration of data from the most recent historical period.

The Industrial Power Users' witness testified that the determination of the cost of equity capital for utilities should not be based on comparisons to the returns earned by industrial firms because there is less risk associated with an investment in utility common stock than with an investment in industrial common stock. The witness supported his opinion with an exhibit which showed that Standard & Poor's 40 Utilities and the group of utilities analyzed by the witness each experienced a smaller variation in earnings per share from mean earnings per share than did Standard & Poor's 400 Industrials over the period 1970-1979.

A Staff witness from the Commission's Accounts and Finance Department presented an exhibit which displayed the capital ratios and costs he proposed be used for ratemaking purposes. The witness did not recommend a return on common equity but showed for purposes of his exhibit a range of equity costs of 14.0% to 16.0%. He utilized Respondent's capital structure of December 31, 1980 but adjusted embedded capital costs to reflect increased costs anticipated for financings planned during 1981. He assumed that the long-term debt financing planned for 1981 would cost 13% rather than 14% as forecasted by Respondent. The witness' exhibit displayed the following information:

Class of Security	Capitalization Ratio	Cost	Weighted Cost
Long Term Debt	49.87%	8.90%	4.44%
Preferred Stock	12.56	8.59	1.08
Common Stock Equity	37.57	14.0-16.0	4.26-6.01
Total Capital 12/31/80	100.00%		10.78-11.53

The Commission has thoroughly reviewed the evidence presented by Respondent on its financing plans and forecasted interest and preferred dividend rates and on anticipated economic and capital market conditions. The Commission is of the opinion that the capital structure and cost rates for senior capital utilized to determine Respondent's cost of capital for purposes of this proceeding should be those based on a capital structure and cost rates at December 31, 1980 adjusted to reflect the effect of the 1981 financing.

Having taken notice of the current cost of capital and based on consideration of all the evidence presented in this proceeding pertaining to cost of capital for Respondent, the Commission is of the opinion and finds that Respondent's cost of common equity for the twelve months ended December 31, 1980 is 15½% and that Respondent's overall cost of capital for the same period is 11.47%.

Respondent's Vice President testified that if a 1980 test year were used, an attrition factor of approximately 0.77% should be added to the cost of capital determined for the twelve months ending June 30, 1982 in arriving at the fair rate of return, in order to provide Respondent with a reasonable opportunity to earn its cost of capital during the first year rates authorized by this Order will be in effect. The Commission is of the opinion that the rate of return authorized in this Order takes account of less than a full year during the first year rates allowed by this Order will be in effect, and accordingly, concludes that the proposed attrition factor not be adopted.

Fair Rate of Return - 1980 Test Year

The Commission has determined to utilize historical data for the twelve months ended December 31, 1980, with appropriate adjustments as hereinabove discussed, as the basis for the test year in this proceeding. The Commission therefore is of the opinion and finds that the fair rate of return which Respondent should be allowed on original cost rate base for the 1980 test year is 11.47%. The corresponding return on fair value rate base as hereinabove determined for the 1980 test year is 9.26%.

The Commission, having examined the entire record herein, and being fully advised in the premises, is of the opinion and finds that:

(1) Respondent is an Illinois corporation engaged in the generation, transmission, sale and delivery of electricity in Illinois and as such is a public utility within the meaning of an act entitled "An Act concerning public utilities," as amended;

(2) the Commission has jurisdiction over Respondent and of the subject matter hereof;

(3) on August 8, 1980, Respondent filed with this Commission tariff sheets containing rate schedules by which it proposed a general increase in electric rates for all classifications of service, effective September 8, 1980; said tariff filing was accompanied by an appropriate supplemental statement in accordance with the rules of the Commission;

(4) due notice of the filing of said tariff sheets was given by Respondent pursuant to law and the rules and regulations of the Commission;

(5) on August 20, 1980, the Commission suspended the filed tariff sheets to and including January 5, 1981, and on December 30, 1980, the Commission resuspended said filed tariff sheets to and including July 5, 1981, all in accordance with the provisions of Section 36 of the Illinois Public Utilities Act;

(6) notice of the initial hearing held in this cause was mailed by the Chief Clerk of the Commission to Respondent, the Mayor, City Attorney and Clerk of the

municipalities within Respondent's electric service areas in Illinois, and to such other persons or entities as are shown by the docket sheets maintained by the Chief Clerk of the Commission, all in accordance with the requirements of the Illinois Public Utilities Act and the rules and regulations of this Commission;

(7) on June 4, 1980, the Commission entered an Order initiating a proceeding to consider adoption of the standards of Section 111 of the Public Utility Regulatory Policies Act as they relate to Respondent; notice of such proceeding was given to Respondent, to all parties allowed to intervene in Respondent's last general rate proceeding, to all parties entitled to notice of a general rate proceeding, and to such other persons and entities as shown by the docket sheets maintained by the Chief Clerk of the Commission for such cause as required by law and the rules and regulations of the Commission; notice was also published in 3 newspapers of general circulation in Respondent's service territory and the official state newspaper; said PURPA investigation was properly consolidated for briefing and decision with the investigation concerning Respondent's proposed electric rate increase;

(8) statements of fact and conclusions reached in the prefatory part of this Order are amply supported by the evidence of record and are hereby adopted as findings of fact;

(9) use of a pro forma test year ended December 31, 1980, with adjustments as adopted herein, is appropriate for ratemaking purposes in this case;

(10) Respondent's original cost electric rate base for the test year ended December 31, 1980 is $1,280,090,000;

(11) Respondent's fair value electric rate base for the test year ended December 31, 1980 is $1,585,400,000;

(12) rates which are presently in effect for electric service furnished to the customers of Respondent do not produce a fair and reasonable return to Respondent on its investment in electric plant in rate base and recovery of operating costs of electric service furnished to its customers; such existing rates are not in all respects just and reasonable and should be permanently cancelled and annulled when rates allowed to become effective by virtue of this Order become effective;

(13) the fair rate of return which Respondent should be allowed on its original cost rate base and fair value rate base as found herein for the test year ended December 31, 1980, is 11.47% and 9.26% respectively;

(14) rates proposed by Respondent for its electric operations in Illinois would produce a rate of return in excess of a return that is fair and reasonable; said filed tariff sheets proposing said rates should be permanently cancelled and annulled;

(15) Respondent should be required to file tariff sheets setting forth rates that will produce annual electric operating revenues of approximately $627,490,000 and result in annual jurisdictional operating income of approximately $146,780,000 for its electric operations in Illinois for the twelve months ended December 31, 1980; such annual jurisdictional operating income would provide Respondent with a rate of return of 11.47% on its original cost electric rate base and 9.26% on its fair value electric rate base; such amounts of operating income and return are not excessive and are fair, just and reasonable;

(16) Respondent should be directed to design the rates to be set forth in the tariff sheets to be filed pursuant to Finding (15) above in accordance with the findings and principles concerning rate design set forth in the prefatory portion of this Order;

(17) the depreciation rates proposed for adoption herein by Respondent are proper and adequate; Respondent should be directed to place such depreciation rates into effect effective June 30, 1981;

(18) adoption of the six electric utility ratemaking standards of Section 111 of the Public Utility Regulatory Policies Act by Respondent is appropriate to implement the three purposes stated in Section 101 of that Act, but only to the extent such adoption is cost-effective; Respondent is, by its filed tariff sheets and otherwise, striving to implement said six standards to the extent implementation is presently cost-effective;

(19) this proceeding and Order and the findings and conclusions contained herein constitute satisfaction of the Commission's obligation under Sections 111 and 112 of the Public Utility Regulatory Policies Act to consider, and determine whether to adopt and implement, the standards of Section 111 with respect to Respondent;

(20) any motions or objections made by any party hereto during the course of these proceedings which are unresolved should be resolved in a manner consistent with the findings of fact and ultimate conclusions herein contained;

IT IS THEREFORE ORDERED by the Commission that the Suspension Order entered August 20, 1980 and the Resuspension Order entered December 30, 1980 be, and they are hereby, vacated and set aside.

IT IS FURTHER ORDERED that the tariff sheets containing rate schedules proposing a general increase in electric rates filed by Respondent on August 20, 1980 be, and they are hereby, permanently cancelled and annulled.

IT IS FURTHER ORDERED that Respondent be, and it is hereby, directed to prepare and file with this Commission tariff sheets for electric service conforming with the provisions of Findings (15) and (16) herein together with other applicable provisions of this Order, which will enable Respondent to reasonably obtain the electric operating results approved herein; said electric tariff sheets should become effective for service rendered on and after the day subsequent to the date of filing same with this Commission.

IT IS FURTHER ORDERED, pursuant to Section 14 of the Illinois Public Utilities Act, that Respondent be directed to place into effect effective June 30, 1981, the electric depreciation rates found to be proper and adequate herein.

IT IS FURTHER ORDERED that any motions or objections made by any party hereto during the course of these proceedings which are unresolved be, and they are hereby, resolved in a manner consistent with the findings of fact and ultimate conclusions contained in this Order.

By order of the Commission this 1st day of July, 1981.

Chairman

Commissioner Helen Schmid, dissenting in part:

This is a dissent only from that portion of this order which establishes a mandatory residential time-of-day rate (Rate 3).

A customer's bills, and the rates for the customer class, should reflect the cost of serving that customer. That basic principle is tempered in each individual case by considerations such as overall class revenue requirement, rate simplicity, freedom from controversy and unreasonable rate discrimination, public acceptability and revenue stability. The utility's cost of providing electricity varies instant by instant. Since the metering for such instantaneous changes in electricity costs to a consumer does not presently exist at a commercial level (and no one in this record has suggested to the Commission such a rate now be adopted), the rate design must, by necessity, approximate or generally reflect this ever changing cost. The extent of the cost approximation, given the considerations mentioned earlier in this paragraph, becomes the focus for class rate design. Over the past few years, and even before PURPA (which standards do not constitute a mandate), this Commission has moved to flatten unjustified declining block rates. The institution of residential summer/winter differential rates is a proper way to convey the fact that the general cost of electric usage during summer is higher than in the winter. The Commission instituted lower rates for the winter months, below what would have been required if a single, year-round, flat rate had been in place.

A mandatory time-of-day rate takes this cost approximation a step further; not only are there rate level differentials based on season but also on daily time periods and days of the week. To impose this type of rate structure on the residential class when there is no shortage of electricity is, at the present time and on the evidence before me, a mistake. Looking at the record, I can find no cost/benefit study to indicate the customer will be "better off" from such a dramatic change. At oral argument, the Company admitted they did not know what will happen. Thus, at the threshold, I have serious doubt on the appropriateness of the mandatory residential rate for this Company. I say "better off" because I believe a proper cost/benefit study should take into account not only direct utility costs, but attempt to reflect the practical imposition mandatory time-of-day rates may have on the residential consumer's lifestyle and on the Company's overall risk.

I happen to be the only Commissioner who has been subject to a time-of-day rate and found it to be, at the very least, impractical. It is next to impossible to adjust the varying lifestyles of a family to a utility's peak load pattern. At present the daily on-peak periods of most Illinois utilities vary from 11 to 15 hours so that shifting usage during the weekday is not easy. The financial penalty for not shifting usage is relatively severe. I question the general residential consumer's acceptance of a mandatory rate. The time-of-day rate should be optional for a residential customer, not mandatory. The public response to the repeated necessity of utility rate relief in recent years causes this Commission enough problems; we need voluntarily seek out no further residential customer complaint.

I am also concerned about the possibility that mandatory time-of-day rates, in conjunction with such rates for other customer classes, may tend to increase overall Company risk as perceived by the capital markets. It would be a tragic irony if a customer could look for some financial benefit from a mandatory time-of-day rate structure only to see it eroded or completely lost because the capital markets perceive the utility as a higher risk investment. I trust parties to future rate proceedings will address this concern.

Based on this record, the rate design considerations generally utilized in the past by this Commission and that type of expertise which arises from personal experience, I do not

believe it is presently in the public interest to institute the proposed mandatory time-of-day rate. This rate, under current circumstances, is, in my opinion, unjust and unreasonable.

Commissioner Daniel Rosenblum, concurring in part and dissenting in part:

I support with enthusiasm the rate design portions of this Order. I cannot agree with the Order's findings regarding revenue requirement and construction work in progress (CWIP). Finally, I accept the remaining portions of the Order.

The rate design portion of the Order represents a significant step toward a rational rate structure. I concur fully in the detailed analysis and conclusion of the Order relating to the importance of marginal cost pricing. I also concur fully with the discussion of mandatory time of day rates. The marginal cost testimony of consumer intervenors, Staff and the Company provided an excellent record. Illinois Power should be commended for its cooperative and generally progressive approach to rate design.

While I agree with the majority that Illinois Power is entitled to substantial rate relief, the final order grants too much money and does not utilize CWIP and the AFUDC equity rate in a manner which provides an adequate return on the current ratepayer's forced investment in Illinois Power's massive Clinton project.

The responsibility of the Commission is to balance the interests of Illinois Power and the ratepayer. In this case that essentially means who pays how much, and when, for the construction of Clinton No. 1. Because of Clinton No. 1, Illinois Power currently has approximately $1 billion invested in construction work in progress. According to Illinois Power's own forecast, investment in CWIP will exceed 57% of total capitalization within another year. This is an enormous investment in one nuclear generating station for a utility of Illinois Power's size and experience-- an investment which has reached its current size because of numerous delays and cost-overruns.

Illinois Power's investment in Clinton No. 1 was made with the Commission's approval. The investment has continued and grown over the objections of consumer intervenors such as the Office of Consumer Services and Central Illinois Consumer Energy Council. Yet, it is consumers (ratepayers) who are being asked to pay.

Whatever the merits of building Clinton, and whatever the reasons for cost-overruns, we must now accept its reality. The reality of Clinton means that we must somehow allow Illinois Power to finance its construction. The difficulty is to somehow provide sufficient revenue while at the same time sharing the risk betw , and balancing the interests of, ratepayers and the Company. It is the balancing of interests which is at the heart of our responsibility to set "just and reasonable" rates. Case law requires this balancing. State Pub. Util. Comm. ex rel. City of Springfield v. Springfield Gas & Elec. Co., 291 Ill. 209 (1919); Cerro Copper Products Co. v. Ill. Com. Comm., 83 Ill. 2d 364 (1980). For this Company, in the midst of its construction program, this Commission must balance the need to provide the Company with the maximum affordable credit ratings, while implementing adequate incentives to complete Clinton in as timely and cost effective a manner as possible and keeping current rates as low as possible.

For purposes of this rate order, this Commission is faced with the need to allow Illinois Power sufficient revenues to maintain interest coverage ratios at levels which will maintain maximum affordable credit ratings and allow the financing of the balance of Clinton construction at the lowest possible cost in accordance with the Hope and Bluefield capital attraction test. Fed. Power Comm. v. Hope Natural Gas Co., 320 U.S. 591 (1944); Bluefield Co. v. Pub. Serv. Comm., 262 U.S. 679 (1923). Both Illinois Power and its ratepayers have a common interest in maintaining the maximum affordable credit rating so as to avoid a derating and resulting higher interest charges. This is neces-

sary since the total cost of the plant, and a reasonable shareholder return on investment, are all costs which are paid by the consumer. The lower these costs are today, the lower rates are in the future.

The focus on interest coverage represents a significant departure from traditional ratemaking. In a traditional rate case, the Commission multiplies a reasonable return on rate base by a rate base. If the Company's operating income is lower (higher) than the result of the multiplication, rates are raised (lowered) until that figure is reached. An interest coverage case turns traditional ratemaking upside down. Instead of concentrating on Illinois Power's electric utility jurisdictional operating income, the focus becomes pre-tax interest coverages of the entire Company, i.e., its Illinois electric operations, Illinois gas operations, FERC-regulated electric operations, and its construction operations at Clinton. The revenue requirement is determined by simply calculating how much revenue is necessary to obtain the desired interest coverages. At this point, the rate of return and the size of the rate base merely become variables used to ratify the increase found by this interest coverage (sometimes called "net income") method. Rate base is increased as necessary by an appropriate amount of CWIP. Some of Illinois Power's exhibits (for example 2.17, 2.19 and 2.21) and its financial ratio arguments comprehend this interest coverage ratemaking method.

While this Commission must be aware of the Company's overall financial creditworthiness and may sometimes use the interest coverage method to determine just and reasonable rates, this method has dangerous side-effects. The method minimizes the Commission's ability to effectively regulate. Those Company expenses normally disallowed for purposes of ratemaking, such as lobbying and some advertising, are included by the financial markets for Company-wide interest coverages. Thus, the rates set by the interest coverage method do pay for those supposedly disallowed expenses through a higher rate of return or more CWIP in rate base, no matter what might be said in the Order. The result is that, under the interest coverage methodology, the Commission's ability to provide meaningful incentives to the Company or to reflect the Commission's determination of management's efficiency is minimized. Wall Street becomes the true regulator.

This Commission should attempt to simulate the free market by rewarding well-run, and efficient public utilities and by not rewarding those which are poorly run or inefficient. Under the interest coverage method, we must provide even the poorly run utility with as much revenue as necessary to enter the capital markets at a reasonable cost. I fear that when the construction period is over, the utilities will revert to their arguments for traditional ratemaking at a time when the interest coverage method might have ratepayer advantage.

The inclusion of CWIP, when combined with the use of interest coverage method, further limits the Commission's ability to provide meaningful incentives for timely and cost effective completion of Clinton. Inclusion of CWIP also creates serious problems of intergenerational equity, and requires ratepayers to make a long-term "forced investment". For ratepayers with high discount rates, particularly those with low income or paying high interest rates for credit, CWIP is a very poor investment. I agree, however, with the majority and with Commissioner Barrett that the Commission does have the statutory authority to include, in its discretion, CWIP in rate base. I also recognize that, <u>at a given level of required revenue</u>, the record reflects that it is cheaper, on a present value basis, to include as much CWIP as possible without lowering the equity return below a reasonable level. Thus, the use of CWIP in rate base, when required to provide a revenue requirement determined by the interest coverage method, results in lower cost to the consumer.

Because of the need to provide sufficient revenue to maintain target interest coverages in this case, inclusion of CWIP is preferable to an extremely high rate of return on equity. Either CWIP or an extremely high rate of return could be used to achieve the same revenue requirement, but the high rate of return would lead to higher future rates because it would be used to capitalize AFUDC. I would include CWIP, however, I would do so _if and only if_ the return on the forced CWIP investment increased so as to provide an adequate return to a ratepayer with a 20% discount rate. I would have reduced the AFUDC equity component by 2 percentage points to increase the return on the forced investment. This lower AFUDC equity component is additionally justified by the guaranteed nature of the equity return. The total cost of Clinton would be lower and the Company would have an increased incentive to complete Clinton quickly, since it would capitalize equity cost of construction at the lower rate of return. I would have allowed an equity return of 15½%, 13½% on the AFUDC equity component, and included $300 million of CWIP, for an increase in required revenues of approximately $90 million.

In the alternative, I would have rejected all CWIP and encouraged rehearing, for the purpose of permitting the Company to attempt to demonstrate a method through which an adequate consumer return on the forced CWIP investment can be obtained.

The majority's Order is based on an interest coverage method of ratemaking which fails to provide adequate incentives to complete Clinton promptly, fails to provide an adequate return on the forced investment in CWIP, and weights the balance too heavily in the Company's favor. I respectfully dissent.

Commissioner Andrew Barrett, dissenting in part:

Today the majority weighed the interests of present ratepayers verses those of future ratepayers and current shareholders; I disagree with the balance struck based on the record.

One of the major rate level issues in this case is the amount of CWIP, if any, to be included in rate base for return purposes. Opponents of CWIP inclusion, led by the Office of Consumer Services (OCS), argue that regulation is a surrogate for competition and that non-utility industrial plant under construction does not generate a return until completion. They argue inclusion of CWIP unreasonably shifts risk from the shareholders to ratepayers during the construction period and that use of AFUDC adequately compensates the Company and shareholder. OCS states that CWIP in rate base gives a utility the incentive to overbuild with capital-intensive plant and provides a disincentive to timely, cost effective construction. OCS argues CWIP in rate base violates the "intergenerational equity" principle followed by this Commission in other regulatory accounting areas such as depreciation, nuclear disposal costs, and tax normalization and, in addition, violates the cost of service standard of pricing electricity. This intervenor further contends that CWIP in rate base is more expensive to residential customers than AFUDC and amounts to a confiscation of ratepayer capital and, as such, is a discriminatory rate in violation of Section 38 of the Public Utilities Act. Finally, this intervenor contends that CWIP is not "used and useful" property, thus, the Commission has no statutory authority to include it in rate base for ratemaking purposes.

On the other hand, the Company argues that this Commission has allowed CWIP in rate base for over 50 years with presumed legislative acquiescence. However, a review of the cited cases shows that the CWIP allowed was either that classified by this Commission as short-term construction on which no AFUDC is calculated, or projects where the order indicated completion would quickly occur. Clinton is still 2 (3? 4?) years from completion. IP also tries to argue "used and useful" can apply to Clinton, but try as it might, it could not do so without changing "and" to "or"; at page 35 of their reply brief, IP asserts the phrase means "one category or the other". The Company states the dollars invested in Clinton are devoted to public utility service and that the record shows CWIP cost less or no more than AFUDC on a present value basis up to a 20% discount rate. The Company states that, generally speaking, today's customers are also tomorrow's customers, Clinton's construction costs and delays are not out of line with the recent industry experience and that CWIP provides no encouragement for IP to build unneeded facilities; the Company has delayed a planned peaker unit and has put Clinton II on indefinite "hold".

I believe this Commission does have the statutory authority to include, in its discretion, a measure of CWIP in rate base (see, for example, Section 30 of the Act). I agree with past orders of this Commission which has found CWIP, under proper circumstances, to be used and useful investment (see, for example, CILCO, Docket 58925, 59179 Consolidated (1975); CIPS, Docket 76-0304 (1977); Illinois Power, Docket 76-0435 (1977); and Illinois Power, Docket 79-0071 (1979)). In the last two Illinois Power general rate orders, this Commission has added major plant CWIP equal to 10% of the Company's original cost rate base without the CWIP. In the February, 1980 Edison rate order (Docket 79-0214), the CWIP included in rate base was much less than 10% of the original cost rate base excluding CWIP. However, IP seeks total CWIP inclusion in rate base of approximately 50% of its original cost rate base excluding all CWIP. This request would, in my opinion, effectively shift a significant amount of construction period risk to the detriment of the ratepayer today. While I agree fully with the current Commission's standard for CWIP inclusion, it appears to me that this is not the proper case to make such a major departure from the informal 10% rule of

thumb. Serious questions still exist about the magnitude of and the reasons for the Clinton cost overruns. To state that Clinton's overruns are consistent with industry experience in similar projects is to admit that electric utilities generally are failing in their collective attempts to control nuclear construction cost increases.

Based on a 10% CWIP allowance which, on this record, means no additional CWIP, and the balance of the order, including the 15½% equity return, with which I agree, the revenue increase required would be $50.63 million dollars, or a 9.67% increase over present rate levels.

Decatur, Illinois
July 7, 1981

Messrs. Wendell J. Kelley B-05
C. W. Wells B-13
W. C. Gerstner B-13
Larry D. Haab B-25

Illinois Power Company
ICC Docket Nos. 80-0544 and 80-0365

The Illinois Commerce Commission issued Illinois Power Company's rate order on Wednesday, July 1, 1981. Attached are seven schedules providing an analysis of that order.

Schedule 1 summarizes Illinois Power's requested electric revenue increase, percentage increase, and rate of return.

Schedule 2 provides a narrative highlighting the important aspects of the rate order.

Schedule 3 provides the imputed rate of return on common stock equity.

Schedule 4 is a summary of the adjustments to net original cost rate base.

Schedule 5 provides a list of proposed adjustments and the Staff position and Commission decision on each one.

Schedule 6 is Exhibit A which shows the amount and percentage of revenue increase by the new revised electric service classifications based on the December 31, 1980 test year.

Schedule 7 provides a comparison of the bill for typical Rate 1 and Rate 2 customers under the new IPC rates and the present rates of other Illinois utilities.

Cheryl Miller

C. K. Miller

RGK/CKM/MFB4

Attachs.

cc: A. E. Gray, B-16
M. P. Mladiner, E-17
E. R. Turner, E-25
L. F. Altenbaumer, F-10
W. M. Davis, E-20
W. T. Hart, S-H-W
O. E. MacBride, S-H-W

Illinois Power Company
ICC Docket Nos. 80-0544 and 80-0365
Twelve Months Ended December 31, 1980
Test Year

Summary

Particulars	Electric Utility
Revenue Increase Requested[1]	$126,700,000
Revenue Increase Granted[1]	104,020,000

Percent Analysis

Percent Revenue Increase Requested	24.4%
Percent Revenue Increase Granted	19.87%
Granted Amount as a Percent of Request	82.1%
Rate of Return Requested[2]	11.42%
Rate of Return Granted[3]	11.47%
Imputed Return on Common Equity Requested	15.0%
Imputed Return on Common Equity Granted	15.5%

1/ All revenue amounts exclude tax additions such as Excess State Public Utility Tax and Municipal Use Tax.

2/ Utilizing Net Original Cost Rate Base and Net Operating Income as proposed by Illinois Power Company.

3/ Utilizing Net Original Cost Rate Base and Net Operating Income found to be appropriate by Illinois Commerce Commission.

Illinois Power Company
ICC Docket Nos. 80-0544 and 80-0365
Summary of Important Aspects of Rate Order

Overview

On July 1, 1981, the Illinois Commerce Commission entered an order in Docket Nos. 80-0544 and 80-0365 granting Illinois Power Company an increase of $104,020,000 in its electric rate revenues. This increase is equivalent to a 19.87% increase in electric rate revenues based on the pro forma test year ended December 31, 1980. Illinois Power had requested an increase of $126,700,000 in rate revenues which would have corresponded to a 24.4% increase. The Commission order provides 82.1% of the Company's electric request.

The most significant aspects of this order relate to the authorized rate of return on common equity and the inclusion of construction work in progress in the rate base. The Commission granted Illinois Power a return on common equity of 15.5% and allowed $375 million of CWIP in rate base. Also notable is the Commission's discussion of the six PURPA ratemaking standards. The order in this docket affirms the appropriateness of all the PURPA standards with special emphasis placed on Commission acceptance of marginal cost and pricing concepts. The Commission also found Illinois Power to be implementing all six standards in an appropriate manner.

Significant Developments

1. Rate of Return

The approved revenue increase is based on an electric rate of return of 11.47% on the electric net original cost rate base. The corresponding rate of return on fair value rate base is 9.26%. The approved revenue increase produces an imputed return on common equity of 15.5% for Illinois Power Company.

Testimony concerning the appropriate rate of return on common equity was presented by Company, Staff, and Industrial Intervenor witnesses. The rates filed by Illinois Power were based upon an imputed return on common equity of 15.0% and a Company witness testified that the current cost of equity for IP was approximately 15%. A witness on behalf of the industrial intervenors claimed Illinois Power's current cost of equity was 13.70%. The Commission Staff supported an imputed return on common equity in the range of 14.0% to 16.0%. The return on common equity granted by the Commission is 15.5% and falls within the range suggested by the Staff. An attrition adjustment of 0.77% proposed by the Company was not accepted by the Commission.

2. Rate Base and Return

Illinois Power Company presented evidence based on the actual year ended December 31, 1980 and the forecasted year ending June 30, 1982. Adjustments to the historical and forecasted operating results appropriate for ratemaking purposes were also presented by Company witnesses. The Commission found that the year ended December 31, 1980 adjusted for known changes was the appropriate test year to be used in this proceeding.

Construction Work in Progress was a major issue in this docket. Illinois Power supported the inclusion of a total of $510 million of CWIP in rate base. Witnesses on behalf of the Office of Consumer Services opposed the inclusion of any CWIP in rate base. Staff witnesses proposed the inclusion of CWIP in rate base but suggested a lower rate of return on the CWIP component of rate base than on non-CWIP rate base.

The Commission did not utilize a variable rate of return to CWIP and approved a total of $375 million of CWIP in rate base. In support of its decision regarding CWIP, the Commission specifically noted (1) the need to maintain the Company's financial integrity particularly relating to internal cash generation and the cash flow needs of the Company, (2) the determination that revenue requirements over the life of Clinton No. 1 will be reduced by approximately $397 million for each $200 million of CWIP included in rate base, and (3) the fact that, even with the approved amount of CWIP, Illinois Power rates will continue to be among the lowest in this state.

The major adjustment proposed by the Company to its return statement related to operation and maintenance expenses. The Company proposed an adjustment to O&M expense to reflect unit cost levels anticipated during the twelve months ending June 30, 1982. Evidence was also presented by the Company to show specifically identifiable increases in payroll and other expenses accounting for over 60% of the proposed adjustment. The Commission adopted this adjustment stating that it was in accordance with past Commission practice.

A summary of proposed Company and Commission Staff adjustments to rate base and return items is attached as Schedule 5. The Commission's decision concerning each adjustment is also noted.

3. Additional Studies

The Commission has ordered Illinois Power to file two studies relating to the feasibility of time-of-day rates. Within 60 days of the date of the order in this docket, the

Company should file a report addressing the feasibility of expanding Rate 3 to approximately 5% of the residential class for the summer season in 1982. Approximately 23,000 customers would be included in such a rate. The Company also was directed to file a report, not later than 120 days following the date of this Order, addressing the feasibility of an explicit time-of-day rate for the largest Rate 11 customers.

As a result of its discussion of the six PURPA standards, the Commission ordered Illinois Power to file two additional studies in future rate cases. A staff witness recommended that in future cases, in addition to its marginal cost studies, the Company should prepare a study on inter-class revenue requirements based on marginal costs. The Staff also recommended that in future cases the Company present cost/benefit studies of Company load management programs and an analysis of customer reaction to them. The Commission adopted both Staff recommendations.

Illinois Power Company
ICC Docket Nos. 80-0544 and 80-0365
Capital Structure and Authorized Rate of Return

Particulars	Capitalization Ratio[1/]	Imputed Rate of Return on Average Common Equity: Earnings Rate	Rate of Return
Long Term Debt	47.94%	8.90	4.26%
Preferred Stock	12.19	8.46	1.03
Common Equity	39.87	15.5[2/]	6.18
	100.00%		11.47%

1/ Capitalization at 6/30/82

2/ Using Rate Case Rate of Return on Net Original Cost Rate Base at 11.47% as authorized by the Illinois Commerce Commission.

Illinois Power Company
ICC Docket Nos. 80-0544 and 80-0365
Rate Base and Operating Income
for Year Ending December 31, 1980

Particulars	Electric Utility Proposed by Company (000)	Electric Utility Granted by Commission (000)
Original Cost Rate Base	$ 910,747	$ 905,090
Construction Work in Progress	510,000	375,000
Net Original Cost Rate Base	$1,420,747	$1,280,090
Rate of Return	11.42%	11.47%
Return Requirements	$ 162,201	$ 146,777
Return at Existing Rate Levels	$ 90,639	$ 89,429
Adjustment for Allocated Income Taxes on Additional CWIP Included in Rate Base	9,495	6,391
Adjusted Return at Current Rate Levels	$ 100,134	$ 95,820
Return Deficiency	$ 62,067	$ 50,957
Revenue Deficiency 1/	$ 126,700	$ 104,020

1/ Revenue deficiency equals return deficiency multiplied by tax factor of 2.04134

Illinois Power Company
ICC Docket Nos. 80-0544 and 80-0365
Proposed Adjustments to Rate Base and Return Items

Adjustments Proposed by IP	Staff Position	Commission Decision
Jurisdictional Adjustment	Not contested	Adopted
Legislative Expense Adjust.	Not contested	Adopted
Leased Appliances	Not contested	Adopted
Depreciation on Contrib. Property	Not contested	Adopted
PUT & MUT Taxes	Not contested	Adopted
Replacement Income Tax Rate Change	Not contested	Adopted
Capital Tax Adjustment	Opposed	Adopted
O&M Adjust. to Reflect 1982 Price Levels	Opposed	Adopted
Real Estate Tax Adjust.	Opposed	Adopted
Interest Expense Adjust.	Opposed	Denied 1/
Proposed Deprec. Rates	Not contested	Adopted
FICA Tax Increase	Not contested	Adopted
Land Held for Future Use (In service after 1990)	Not contested	Adopted
Fuel Inventory Price Adjust.	Opposed	Denied 1/
CWIP Additions	Partially Supported	Partially Accepted

Additional Adjustments Proposed by Staff	Commission Decision
Advertising Expense Adjustment	Adopted
ITC Amortization Adjustment	Denied
UFAC Return Adjustment	Denied 2/

1/ Commission denied IP adjustment in favor of adjustment proposed by Staff witness.

2/ Since UFAC provision was denied by the Commission, this adjustment was unnecessary.

Exhibit A
Final Rates

ILLINOIS POWER COMPANY

Estimated Electric Revenue Increase
Twelve Months Ended December 31, 1980

Line No.	Service Classification (1)	Customers (2)	Mwh (3)	Revenue Increase 1/ Amount (000) (4)	Revenue Increase 1/ Percent (5)
1	1	112,363	343,000	$ 2,800	16.0%
2	2	353,279	3,587,000	36,500	21.0
3	3	897	48,000	200	12.2
4	4	7	-	-	15.5
5	Residential Subtotal	466,546	3,978,000	39,500	20.5
6	10	27,847	137.000	1,900	19.9
7	11	26,699	2,306,000	20,500	19.0
8	13	-	5,000	-	14.4
9	General Service Subtotal	54,546	2,448,000	22,400	19.1
10	21	320	2,737,000	19,200	20.8
11	24	34	2,892,000	16,400	20.6
12	30	2	207,000	700	14.5
13	Individual Contracts	3	667,000	3,000	18.4
14	Industrial Subtotal	359	6,503,000	39,300	20.4
15	39	-	76,000	400	9.6
16	45	379	54,000	700	23.2
17	Lighting Subtotal	379	130,000	1,100	14.7
18	41	284	195,000	1,400	25.0
19	42	32	41,000	300	24.1
20	Municipal Service Subtotal	316	236,000	1,700	24.8
21	Total	522,146	13,295,000	$104,000	20.1%

1/ Based on actual fuel cost adjustments for the twelve months ended December 31, 1980.

Schedule 6

C

Illinois Power Company
ICC Docket Nos. 80-0544 and 80-0365
Electric Bill Comparisons

Utility	S.C. 1 1/ Annual Amount	S.C. 1 1/ Percent Over or (Under) IP Revenue	S.C. 2 2/ Annual Amount	S.C. 2 2/ Percent Over or (Under) IP Revenue
Illinois Power	$210.35	- %	$676.17	- %
Union Electric	190.75	(9.3)	558.89	(17.3)
Iowa-Illinois G&E	241.98	15.0	782.51	15.7
Central Ill. Pub. Serv.	249.62	18.7	751.75	11.2
Central Ill. Light Co.	256.67	22.0	763.84	13.0
Commonwealth Edison 3/	273.93	30.2	872.90	29.1

1/ Typical small residential customer with annual usage of 3,522 kwh.

2/ Typical residential customer with annual usage of 11,465 kwh.

3/ Commonwealth Edison rates effective July 2, 1981 were not available. The reported amount was estimated by increasing the previous rate by 14%.

Illinois Power Company
ICC Docket Nos. 80-0544 and 80-0365
Electric Bill Comparisons

	S.C. 1 1/		S.C. 2 2/	
Utility	Annual Amount	Percent Over or (Under) IP Revenue	Annual Amount	Percent Over or (Under) IP Revenue
Illinois Power	$210.35	- %	$673.54	- %
Union Electric	190.75	(9.3)	558.89	(17.0)
Iowa-Illinois G&E	241.98	15.0	782.51	16.2
Central Ill. Pub. Serv.	249.62	18.7	751.75	11.6
Central Ill. Light Co.	256.67	22.0	763.84	13.4
Commonwealth Edison	256.05	21.7	817.98	21.4

1/ Typical small residential customer with annual usage of 3,522 kwh.

2/ Typical residential customer with annual usage of 11,465 kwh.

EXHIBIT IP-8

STATE OF ILLINOIS

Illinois Commerce Commission

527 EAST CAPITOL AVENUE

SPRINGFIELD, ILLINOIS 62706

January 13, 1983

RECEIPT ACKNOWLEDGED
1/14/83
C. J. ZEMAITIS
STATE REGULATORY MATTERS
ILLINOIS POWER COMPANY

Re: 82-0152

Dear Sir/Madam:

Enclosed herewith is certified copy of order entered by the Commission.

Kindly acknowledge receipt.

Very truly yours,

Rose M. Claggett

Rose M. Claggett
Chief Clerk

RMC:alb

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Power Company	:	
	:	82-0152
Proposed general increase in	:	
electric and natural gas rates.	:	

ORDER

By the Commission:

On February 19, 1982, Illinois Power Company ("Company," "Respondent" or "Illinois Power") filed revised tariff sheets in which it proposed general increases in its electric and gas rates effective March 22, 1982.

Notice of the proposed general rate increase was posted in a conspicuous place in each of Respondent's business offices and published in newspapers of general circulation throughout Respondent's service area, and the proper sheets were maintained for public inspection in Respondent's business offices pursuant to the requirements of Section 36 of the Illinois Public Utilities Act and the provisions of General Order 157, Revised, of the Commission. Respondent has also complied with the "prefiling" requirements contained in the Commission's General Order 210.

An examination of the filed tariff sheets resulted in a determination by the Commission that hearings should be held concerning the propriety and reasonableness of the proposed general increases and that, pending hearing and decision thereon, the filed tariff sheets should not become effective. Therefore, on March 10, 1982, the Commission entered an Order suspending the effective date of the filed tariff sheets to and including July 19, 1982, and on July 14, 1982, the Commission resuspended the effective date of the filed tariff sheets to and including January 19, 1983.

Petitions to Intervene were filed on behalf of Central Illinois Consumer Energy Council; The People of the State of Illinois ("People"); U.S. Department of Defense; Illinois Public Interest Research Group ("IPIRG"); A.E. Staley Manufacturing Company; Monsanto Company; Jones & Laughlin Steel Corporation; Olin Corporation; Borg-Warner Chemicals Division of Borg-Warner Corporation; General Tire & Rubber Company; General Motors Corporation; The Illinois Association of Community Action Agencies ("IACAA"); Madison Concerned Citizens Organization; Jessie Mae Marble; Beverly M. Cafin; Ebbie Lee; Merdice Robinson; Gertrude Palmer; Edna Rowan; Vermilion County Citizens Action Committee for Economic Opportunity, Inc.; School District 116 Board of Education, Champaign County, Illinois ("Urbana School District"); Carlisle Tire and Rubber Company, Division of Carlisle Corporation; PPG Industries, Inc.; Granite City Steel Division of National Steel Corporation; Amoco Chemicals Corporation; Community Unit School District No. 3 Board of Education, Champaign and Piatt Counties, Illinois ("Mahomet-Seymour School District"); McNeil Asphalt Co.; Anthony-Oak, Inc.; Champaign Asphalt Company; University Asphalt Co.; Keene Road Builders, Inc.; Maclair Asphalt Company, Inc.; Reese Construction Company; Gunther Construction Company; Illinois Asphalt Pavement Association; Illinois Valley Paving Company; Advanced Asphalt Company; Wabash Asphalt Company, Inc.; Firestone Tire & Rubber Company; and Randall L. Plant.

In addition the following municipalities filed Petitions to Intervene or became formal intervenors by causing to be filed the written appearance of their attorneys: Town of Normal, Village of Buffalo, City of Galesburg, City of Spring Valley, City of Peru, City of LaSalle, City of Kewanee, City of Belleville, City of Danville, City of Urbana and Village of Glen Carbon.

All persons and entities hereinbefore listed were granted intervention by Order of this Commission and allowed full opportunity to participate in these proceedings.

Pursuant to notice as required by law and by the rules and regulations of this Commission, the initial hearing in this cause was held before a duly authorized Hearing Examiner of the Commission at its offices in Springfield, Illinois, on April 16, 1982. In addition to Respondent and Intervenors, appearances were entered by members of the Commission's Economics and Rates, Accounts and Finance and Engineering Departments and its Policy Analysis and Research Division ("Staff" or "Staff witness"). Subsequent to the initial hearing date additional hearings were held at the offices of the Commission or elsewhere on forty-one days as shown by the docket sheets maintained by the Chief Clerk of this Commission for purposes of this cause and as a part of the record in this case. Hearings were also held in the Illinois municipalities of Danville, Urbana, Bloomington, Spring Valley, Decatur, East St. Louis, Kewanee, Belleville, Granite City and Galesburg, at which times statements were made by and on behalf of certain members of the public and other entities having an interest in the subject matter of this proceeding.

On October 1, 1982, at the conclusion of full and public hearings, the record in this proceeding was marked "Heard and Taken." Briefs were filed by the parties. Oral argument was heard by the Commission on January 4, 1983, at which time the matter was marked "Heard and Taken under Advisement."

The record contains in excess of 4,700 pages of transcript and numerous pages of prepared written testimony and statistical and other exhibits. The record provides a detailed analysis of the financial affairs of Respondent, its operating revenues and expenses, the original cost and trended original cost and associated accrued depreciation of Respondent's property, the cost of capital and other matters relating to rate of return and other issues raised in this case.

NATURE OF RESPONDENT'S OPERATIONS

Illinois Power furnishes electric and gas service within areas of Illinois comprising approximately 15,000 square miles. At December 31, 1981, the Company furnished electric service to approximately 525,426 electric customers in 422 communities, in areas having a population of approximately 1,405,000. The largest cities in which electric service is provided are Monmouth, Galesburg, Kewanee, LaSalle and Ottawa in north central Illinois; Bloomington, Normal, Jacksonville, Decatur, Champaign, Urbana and Danville in central Illinois; and Wood River, Granite City, Collinsville, Belleville, Centralia and Mt. Vernon in southwest Illinois.

The Company's electric generating facilities have a net summer capability of approximately 3,815 MW, with approximately 3,626 MW in five conventional steam generating plants and the rest in other generating facilities including internal combustion and hydro units. Respondent also has approximately 55 MW of capacity available under contract with Electric Energy, Inc., and maintains interconnections with major neighboring utilities.

Illinois Power is currently constructing a sixth generating station near Clinton, Illinois, designated as Clinton Unit No. 1. Respondent will own 760 MW of this unit and two wholesale electric cooperatives will own the remaining 190 MW. Respondent's evidence indicates that Clinton Unit No. 1 is scheduled to be in service in August 1984 at an estimated final cost of $2,170,086,000.

At December 31, 1981, Respondent furnished gas service to approximately 383,474 gas customers in 322 communities having a total population of approximately 1,075,000. The largest cities in which gas service is provided are the same as those in which electric service is provided, with the exception of Ottawa, Bloomington and Normal, and the addition of East St. Louis and Peru, Illinois.

PROPOSED CHANGES IN ELECTRIC RATE SCHEDULES

The proposed changes in charges for electric service include general increases for all retail service classifications. Respondent's witness testified that the proposed revenue requirements and revenue increase by class were based on the results of a marginal cost of service study which showed that the municipal and residential customer classes provide a relatively low percentage recovery of marginal costs at current rates. Respondent's proposed rate design results in larger percentage increases for these classes than for other classes of service.

A Staff witness stated that Respondent's proposed allocation of its electric rate increase among the customer classes makes substantial progress in bringing class revenues in line with cost of service, referring to a marginal cost of service study presented by another Staff witness. The Staff witness proposed two rate design changes, discussed in a subsequent section of this Order, that would result in an allocation of revenues slightly different from that proposed by Respondent. The rate design Staff witness also recommended that any reduction in Respondent's proposed rates be made on a pro rata basis in all service classifications except S.C. 30 and Rider S, which would remain as filed, and S.C. 10 and 42, which would receive a reduction of 25% more than the proportionate amount of the overall reduction.

A witness appearing on behalf of Industrial Power Users stated that embedded cost studies deserve greater weight than marginal cost studies in determination of cost responsibility of the various customer classes. He recommended the allocation of a greater percentage of the proposed increase to the residential class, and a smaller percentage to the industrial class. He considered cost of service principles and the principle of gradualism. Specifically, the relative percent increases were limited to a maximum of 1.5 times the average percent increase (excluding fuel recovery).

This Industrial Intervenor witness testified that residential rates under his proposed allocation to the residential class still fell short of the cost of serving that class under either an embedded cost or marginal cost measure, and that the industrial rates resulting from his allocations to the large general service and large power classes exceeded both embedded and marginal costs. The witness recommended that any reduction in the requested rate levels be allocated among the classes in the same proportion as the witness used to allocate the increase, and that any reduction in industrial rates be accomplished by reducing energy charges only.

The Commission is of the opinion that Respondent's allocation of its proposed rate increase among the various classes of service, with the exception of S.C. 10, reflects the marginal costs of serving each class to the extent possible without providing a disproportionately large increase to any one class. Illinois Power's allocation of its proposed rate increase is therefore approved, and any reduction in rates necessary to comply with this Order shall be made on a pro rata basis except to S.C. 30 and Rider S, which should not be reduced from the filed rates and Service Classification 10 which should receive a reduction of 25% more than the proportionate amount of the overall reduction.

Rate Design Principles and Cost of Service Information

Respondent presented in evidence both embedded and marginal cost data, but relied on marginal cost information in designing its proposed rates. Respondent's witness presented data on marginal energy costs by rating period and by functional level of service; marginal demand costs, including marginal costs of generation,

transmission and distribution capacity; and marginal customer costs. Another Company witness testified that marginal costs were used in establishing energy, demand and customer charges.

Other marginal cost data was presented by Staff and Residential Intervenor witnesses. An embedded cost study was presented by an Industrial Power Users witness.

Three witnesses testifying on behalf of the Industrial Power Users offered evidence attacking the propriety of basing electric rates on marginal cost. The position taken by these witnesses was that rates should be based on the embedded costs used by the Commission to determine the utility's revenue requirements. The witnesses identified numerous problems associated with the use of marginal costs in setting utility rates, and also testified that many methods for implementing marginal cost based rates can result in unfair, non-cost-justified burdens being placed on larger industrial customers which may lead these customers to reduce operations in, or to leave, a particular utility's service area, to the detriment of the economy of the area and of the remaining customers who must bear a larger portion of the utility's fixed costs.

The Commission has fully reviewed all the evidence submitted by the parties hereto on the appropriateness of using marginal cost or embedded cost as the basis for rate design. The Commission finds no basis in the record to change its position on this matter established in Respondent's last rate Order in Docket Nos. 80-0544 and 80-0365. In that Order, the Commission concluded that marginal costs provided a reasonable basis for electric rate design. Other criteria such as historical continuity of rate design, customer impact and understanding, and revenue stability deserved secondary consideration. The Commission is of the opinion that the marginal cost data presented by the Staff witnesses provide a proper basis for the design of electric rates and should be utilized for that purpose in this proceeding.

Respondent's cost-of-service witness presented evidence showing Respondent's load weighted marginal energy cost at the generation level by rating period for the years 1982 through 1986. The witness testified that these marginal costs include only the out-of-pocket costs, such as fuel and variable operation and maintenance expense, incurred in serving additional firm load. The witness stated further that by making additional firm sales, Illinois Power may have to forego the opportunity to sell economy energy on the interchange market and, therefore, loss of interchange profits is an additional cost of serving native load. Respondent attempted to determine the amount of this additional cost and included it in marginal energy cost as an opportunity cost adjustment factor.

Two witnesses for the Industrial Power Users opposed the use of an opportunity cost adjustment factor. They argued that loss of profits on interchange sales should not be considered in determining marginal energy costs because Respondent has no obligation to serve other utilities. They also claimed that use of the opportunity cost adjustment destroys the basic concept of calculating costs, and results instead in the calculation of the price to some other utility at which Respondent could sell power. This position was also persuasively argued in the Brief filed on behalf of the asphalt contractors, active Intervenors in this proceeding. A Staff witness also opposed use of an opportunity cost adjustment, citing practical problems in estimating opportunity costs.

Respondent's cost-of-service witness defined the marginal capacity cost of generation as the cost of adding generating capacity to meet peak demand. He testified that the least expensive capacity that can be added to meet peak demand is a combustion

turbine, and that Illinois Power used the costs associated with the addition of a combustion turbine in determining its marginal capacity cost of generation. Witnesses for Residential Intervenors as well as Commission Staff witnesses supported Respondent's method.

An Industrial Power Users witness opposed Respondent's method claiming that the costs associated with addition of a combustion turbine are the costs of meeting increased demands of short duration only. Respondent's witness testified in rebuttal that addition of base load capacity might be the lowest cost option in meeting increased demands of longer duration, but only if the savings in energy costs outweigh the additional capacity costs of the base load unit relative to the combustion turbine. In that case, after removing the cost associated with energy savings, the remaining demand-related portion of the cost of the base load unit would be less than the cost of the combustion turbine. The witness concluded that the combustion turbine method therefore determines the maximum cost of meeting additional demand regardless of the duration of that demand.

It is the Commission's opinion that the specific energy charges in Respondent's proposed tariffs are overpriced to the extent that they contain a marginal energy cost which includes an opportunity cost adjustment factor. The opportunity cost adder used by the Company has been shown by both Intervenor and Staff witnesses to be conceptually flawed. A Staff witness has shown further that the 1980 data used to calculate the foregone opportunity of interchange sales is an unreliable method to calculate the opportunity cost for rates effective in 1983. The Company's 1983-84 marginal energy costs revised for the delay in the Clinton project but without the opportunity cost adjustment are the appropriate costs for setting rates in this case. The use of combustion turbine costs to estimate marginal generation cost is a theoretically sound method that has found widespread application in the electric utility industry and should be accepted in this case.

Residential Service Classifications

Respondent proposed increases in facilities charges and all rate blocks for S.C. 1 and 2. Respondent has designed its proposed S.C. 1 to eliminate the initial winter energy block and to increase the differential between summer and winter charges to 4.05¢ per KWH. The same differential applies to the summer charge and winter tail block charge in proposed S.C. 2, and a differential of 0.93¢ per KWH is established between the summer energy charge and the first block winter charge. Respondent proposes to reduce the threshold for mandatory time-of-day service under S.C. 3 from 150 to 140 KWH per day, and to increase the time-of-day differential from 0.55¢ per KWH to 1.00¢ per KWH. S.C. 3 would be made optional for customers below the 140 KWH per day threshold, and S.C. 4, optional residential time-of-day service, would be eliminated.

Respondent proposes facilities charges of $9.50 per month for S.C. 1 and $10.50 per month for S.C. 2 single phase service. Respondent presented a marginal cost of service study which showed that current revenues including facilities charges recover approximately 60% of marginal cost including customer costs.

Respondent's cost-of-service witness defined the cost of connecting a new customer to Respondent's system as the carrying charge on facilities needed to provide the customer with minimal load, and the cost of operating and maintaining those facilities. The witness testified that some distribution primary and secondary costs are customer-related because a portion of distribution plant is required to stand ready to serve the customer

regardless of his energy usage. Illinois Power used minimum size and zero intercept methods to classify embedded distribution costs for the years 1976-1980 into demand-related and customer-related components.

Respondent also conducted an engineering analysis of customer work orders to determine the cost of minimum size facilities that would be necessary to connect a new customer to the system. In this study, Illinois Power analyzed a sample of work orders for new installations connected to the system in the last three years. Based on both of these studies, Respondent found marginal customer costs to be in the range of $18 to $28 per month.

The cost-of-service Staff witness recognized Respondent's engineering analysis to be a proper method for classification of distribution system investment into customer-related and demand-related components. The Staff witness excluded minimum distribution costs from his marginal cost analysis on the grounds that, although these costs are clearly not demand-related, it is equally clear that they are not customer-related. Hence these costs can not be considered marginal. The Staff witness' cost study showed that current revenues for the residential class recover approximately 83% of the marginal cost of serving the class.

A Commission Staff witness testified that facilities charges should be based on the marginal cost of the service drop, meters, meter reading and miscellaneous customer expense. Using the data presented by Respondent, the Staff witness testified that the cost of these items was $7.67 per month and recommended that facilities charges for residential rates be set at that level. The Staff witness proposed to recover the revenue foregone in lowering the facilities charge by raising energy charges to levels closer to marginal cost.

The witness testifying on behalf of the Residential Intervenors did not attempt to determine facilities charges based on marginal customer costs. The witness recommended that energy charges should first be set based on marginal demand and energy costs, and that any revenue thereby produced in excess of the legal revenue requirements determined by the Commission should be reduced by lowering the facilities charge to a minimum of $1.00 per month. The witness testified that the cost of the minimum distribution system should be classified as a marginal demand cost. Using his calculation of marginal cost-based revenues and based on the proposed full revenue requirements for the residential class, this witness recommended a facilities charge of $2.45 per month.

The Commission is of the opinion that, in order to insure proper cost recovery and equitable apportionment of cost responsibility among customers, and to avoid the pricing of energy charges above marginal cost, residential facilities charges should move toward residential marginal customer costs when the revenues collected by pricing all rate components at marginal costs fall short of the revenue requirement. However, Respondent's proposed residential customer charges of $9.50 and $10.50 per month respectively produce excessively large bills to the low usage consumers under both rates. For the purposes of this case, the Commission finds that customer charges of $5.00 and $6.50 for Service Classifications 1 and 2 are reasonable and should be implemented at this time.

A rate design Staff witness proposed residential rates with higher energy charges than those proposed by Illinois Power. Respondent's proposed rates produce increases of 20% to space heating customers in both residential service classifications. The Commission Staff witnesses' proposal results in a larger percentage increase for space heating customers as opposed to non-space-heating customers. Respondent's witness stated in rebuttal that this sends an erroneous price signal to space-heating customers that costs of serving them are increasing faster than costs of serving non-space-heating customers.

The witness for Residential Intervenors presented proposed residential rates designed to recover 100% of Respondent's proposed revenue requirements, 50% of the proposed increase in revenues and the current revenue requirements, based on 1981 usage. Steps or phases for moving from the current rates to the full marginal-cost based rates were also presented, though no time period for reaching the final proposed rate was suggested. It was recommended that S.C. 1 be abolished and that charges to all non-time-of-day residential customers be based on one rate.

A Commission Staff witness testified that the rate relationship between S.C. 1 and S.C. 2 are confused when a winter discount to conserve in the summer is given, and that frequent rate switching makes it difficult for customers to anticipate the amount of their bills. The Commission Staff witness recommended that S.C. 1 and S.C. 2 be combined when this can be done without disproportionate increases to S.C. 1. The Commission Staff witness found no cost differences in serving the two classes of customers.

Respondent's witness objected to the rates and rate design proposed by the Residential Intervenor witness on the grounds that: (1) his method of rate design would lead to rates which result in very large increases in summer energy charges, (2) he failed to adequately consider customer impact, and (3) he failed to reflect marginal customer cost in the facilities charge. Typical bill comparisons submitted by the witness showed that his proposed rates would cause disproportionately high monthly and annual bill increases to many of Illinois Power's customers. Under the various percentage increases and consumption patterns considered in the witnesses' billing comparisons, many customers would receive large increases in summer bills with slight reductions in some or all of the other months.

The Commission agrees with Staff witnesses and Residential Intervenors that the current offering of separate Rates 1 and 2 does not send an effective price signal to all residential customers, but finds that combining the rates in this case produces excessive charges for many customers. In the interim, however, the proposed seasonal differential for Service Classification 1 is too wide and should be moderated through retention of the existing 2-block structure for winter usage. The energy charges in Service Classifications 1 and 2 should be determined in the following manner: the initial winter energy block for both rates should remain at the present level; the winter tailblock for both Service Classifications 1 and 2 should be increased to 3.9¢ per KWH. The summer energy charge in each rate should be established at the same level for both rates. The Company should, at its next rate filing, propose a single rate available for all customers currently on Service Classifications 1 and 2. The Commission is of the opinion that residential time-of-day rates should not be expanded until full analysis of the efficacy of such rates by this Commission has been completed.

General Service Classifications

Respondent proposes increases in all charges for the general service rates, S.C. 10, 11 and 13. In addition, Respondent proposes to lower the maximum contract capacity provision in S.C. 11 from 500 to 400 KW. Respondent's rate design witness testified that this will shift approximately 100 customers with total consumption of approximately 170,000,000 KWH to a time-of-day rate under S.C. 21.

A Staff witness recommended a reduction of 0.4¢ in S.C. 10 energy charges. This would eliminate the 0.3¢ differential currently maintained over the S.C. 11 energy charge. Respondent's witness testified that this differential is designed to recover transformation costs that are recovered through a separate charge of 50¢ per KWH

in proposed S.C. 11. This witness stated that if the differential were eliminated, a customer moving from one of these rates to the other would see a change in his bill that would not be justified by any change in transformation costs.

Based on all the evidence the Commission is of the opinion that the Staff witness' proposed reduction of the summer energy charge for S.C. 10 is not supported by cost and should not be accepted. The Commission does accept the Staff witness proposal to give S.C. 10 a 25% greater share of the proportionate reduction from filed rates. Adjustments to filed rates to meet the revenue award should come from the first block of the winter energy charge and the customer charge.

Industrial Service Classifications

Respondent has proposed a number of changes to its industrial rates that were not contested by other parties. Under the proposed rates, demand charges are based on maximum monthly on-peak demand instead of a contract capacity. Interruptible service is provided under a time-of-day rate, increasing by approximately 300 million KWH the amount of Respondent's energy sales that are subject to time-of-day provisions. The minimum capacity reservation for S.C. 30, Limited Firm Service, has been reduced from 2,000 KW to 1,000 KW, making interruptible service available to approximately 70 additional large power customers.

Respondent also submitted a number of changes to the terms and conditions of its proposed industrial electric rates as originally filed. These changes affect S.C. 21 and 24, Rider S and the contracts with Granite City Steel and the University of Illinois. These changes are reflected in the following proposed tariff sheets as shown in Respondent's Exhibit 6.23: Second Revised Sheet No. 20, Second Revised Sheet No. 21, Third Revised Sheet No. 22, Second Revised Sheet No. 43, Third Revised Sheet No. 44, Original Sheet No. 44.1, Tenth Revised Sheet No. 11, Eighth Revised Sheet No. 12, Seventh Revised Sheet No. 13, Seventh Revised Sheet No. 14, Fourth Revised Sheet No. 15, all to Section 1 of Appendix to Schedule of Rates; and Seventeenth Revised Exhibit B to Agreement Approved in Docket No. 53475; all of ILL.C.C. No. 27, Schedule of Rates for Electric Service.

The Commission finds that all the foregoing changes are reasonable and they are therefore approved.

The Industrial Power Users' electric rate design witness testified that embedded cost of service data should be given greater weight than marginal cost information in designing rates. The witness proposed alternative rates for S.C. 21 and 24 customers based on embedded costs. This witness stated that Respondent's proposed industrial rate design, which includes lower demand charges and higher energy charges than those recommended by the witness, has the effect of recovering fixed costs in energy charges thereby subjecting Respondent to revenue or earnings instability should industrial energy sales rise or fall faster than industrial customer billing demands.

Four witnesses on behalf of the asphalt contractors testified that lowering the availability of Service Classification 11 from 500 to 400 MW will result in increases as large as 176%. In rebuttal, the Respondent proposed to provide such customers a "bill limiter" that prevents any customer moving to Service Classification 21 from Service Classification 11 from receiving demand and energy charges, exclusive of fuel adjustment and add-on taxes, in excess of 10.1¢ per KWH in the summer and 8.5¢ per KWH in the winter.

A Commission Staff witness proposed a seasonal differential of 0.5¢ per KWH in on-peak energy charges under S.C. 21, 24 and 30. Respondent and Staff witnesses both agreed that the cost differential will be in effect for two years. Respondent's witness stated that since there is no long-term seasonality in marginal energy costs, there should be no seasonal differential in energy costs. The witness further testified that the only way to implement seasonal energy costs without meter changes is to define the seasons by billing periods based on meter reading dates, similar to S.C. 3; and that the problem with this approach is that the period for which the rates are determined, June 15 through September 14, does not necessarily match the billing periods.

Respondent proposes a new S.C. 25 for industrial customers willing to guarantee an annual load factor of approximately 80%. Respondent's witness testified that this rate is similar to S.C. 24, except the customer guarantees a higher load factor and receives a greater energy charge discount. Under Respondent's S.C. 24, the customer agrees to pay for 400 KWH per KW of contract capacity (equivalent to a load factor of approximately 55%) in exchange for a discount of .15¢ per KWH from the energy charge that he would otherwise pay under S.C. 21. A customer taking service under proposed S.C. 25 would guarantee payment for 585 KWH per KW of contract capacity, and receive a discount of .20¢ per KWH.

A Commission Staff witness recommended elimination of S.C. 24 and, by implication, rejection of proposed S.C. 25, on two grounds. The Staff witness asserted that the rate structure does not carry a strong price signal because customers unable to use the full amount of energy that they agreed to purchase may evaluate their marginal cost of electricity at zero. The Staff witness also claimed that Respondent has not shown the amount and value of the reduction in revenue fluctuation achieved by S.C. 24.

Respondent contended that at the time when an industrial customer contracts to maintain a certain load factor and incurs the risk of unused consumption, he receives the proper price signal. According to Respondent, the implication of the Staff witnesses' objection is that a customer facing unused consumption might make a wasteful or inefficient use of energy, and that the only possible way to use a substantial amount of electricity in this manner would be to use it in a process that currently employs another fuel. Illinois Power points out that a witness for the Industrial Power Users testified that fuel switching is impossible in many industrial end uses, and where it is possible, it is impractical in the short run because of the capital investment and lead time required. Further, Respondent's witness testified that some customers actually incur unused consumption, which leads Respondent to conclude that the Staff witnesses' concerns about wasteful energy use are unfounded.

Respondent further stated that even if the benefits of guaranteed load factor rates are difficult to quantify, they should not be ignored. The principal benefit claimed by Respondent is that these rates guarantee a certain level of revenues and thus allow Respondent to shift a portion of its business risk to its industrial customers. Customers not willing to assume the risk can take Rate 21, which is equivalently priced except for the load factor discount of approximately 4%.

The Commission is of the opinion that the proposed industrial rate design appropriately reflects marginal demand and energy costs except for the lack of seasonality in the time-of-day energy charges. However, implementing a seasonal time-of-day rate for only two years will send a confusing price signal to customers. S.C. 24 has been shown not to produce the ill effects discussed by the Staff witness, i.e. that it encourages wasteful consumption or gives too large of a discount. The Staff witness' cost study in fact shows that S.C. 24 is set at an appropriate level of cost recovery and should be adopted for purposes of this case. The Commission rejects the establishment of S.C. 25 as the Respondent has failed to show that the additional guarantee of revenues provides any significant value to the Company at this time, and because pricing studies of this kind should not be extended without further careful study.

The Commission accepts the Staff witnesses' recommendation to set winter tailblock demand charges at $2.50 per KW and to adjust filed rates to awarded revenues by lowering the first block of the winter demand charge while keeping this charge the same for both S.C. 21 and S.C. 24 service classifications.

Municipal Service and Lighting Service Classifications

Respondent proposes increases in the municipal service rates, S.C. 41 and 42, and in the lighting rates, S.C. 39 and 45. Respondent's witness testified that proposed municipal service rates remain lower than proposed general service rates in recognition of franchise and long-term contract benefits provided to Respondent by its municipal customers.

A Commission Staff witness proposed to eliminate the distinction between S.C. 10 and S.C. 42 by combining the two rates. S.C. 42 customers who move to S.C. 10 would have the same rates as proposed by the Company. Respondent's witness testified in rebuttal that some S.C. 42 customers would not qualify for S.C. 10, and that some of the large low load factor customers transferring to S.C. 11 and 21 would be adversely affected due to significant rate increases.

The Commission finds that the municipal service and lighting rates and rate design proposed by Respondent are reasonable and should be adopted. The proposed rates should be lowered in a manner that maintains the relative rate relationship with general service rates

PROPOSED CHANGES IN GAS RATE SCHEDULES

The proposed increases in charges for gas service include general increases for all retail service classifications except for interruptible service. Respondent proposes to restructure its commercial and industrial rates by classifying customers now served under S.C. 63 and 66 into proposed S.C. 63, 64 and 65. Present S.C. 66 would be eliminated. Respondent's witness testified that the Company's gas revenue requirements are determined primarily by customer costs, so that allocation of the rate increase among the various classes of service depends primarily on the extent to which current facilities charges reflect marginal customer costs. Illinois Power's gas marginal customer cost study showed that the disparity between facilities charges and marginal customer costs was greatest in the residential and small commercial service classifications. These classifications received larger percentage increases than those received by the large commercial and industrial service classifications under Respondent's proposed rate design.

A witness for Respondent testified that the proposed gas rates were designed to recover the requested revenue increase by first establishing facilities charges at marginal customer cost, to the extent possible, without creating adverse customer impact, and then increasing all commodity charges by a uniform amount per therm to recover the remainder of the increase, taking into account the range of marginal commodity costs established by Respondent's cost of service study. Accordingly, the witness recommended that any reduction in proposed rates necessary to comply with this Order should be made by uniform reductions in commodity charges, with a lower limit for commodity charges established by the average cost of gas. The witness pointed out that this method of rate reduction will help offset the increase in total commodity charges due to purchased gas adjustment increases.

A rate design Staff witness stated that Respondent's marginal gas cost studies were useful in rate design and class revenue allocations. He accepted the Company's allocation of the proposed increase, noting that the difference in rate levels followed cost patterns. The Staff witness recommended that any reduction from the proposed rates be allocated among the classes in the same proportion as the proposed increase. He proposed to decrease the proposed charges by reducing the declining block characteristics of the various gas service classifications.

An Industrial Power Users witness recommended allocation of a greater percentage of the proposed increase to the residential class. He stated that his recommendation was based on consideration of both embedded and marginal cost studies. He also recommended that any reduction in the proposed rates be allocated among the classes in proportion to his allocation of the increase, and that any reduction be accomplished by reducing commodity charges only, leaving facilities charges intact.

Rate Design Principles and Cost of Service Information

Respondent presented in evidence both embedded and marginal cost data, but relied primarily on marginal cost information in designing its proposed rates. Respondent's witness presented data on marginal customer costs by size of metering installation, and marginal commodity cost of gas as influenced by weather severity. Respondent's witness testified that Illinois Power's proposed commodity charges were based on marginal commodity costs, and that proposed facilities charges were based on marginal customer costs.

Respondent's rate design witness testified that, in addition to recovering costs including a fair return on investment, other criteria were used in developing the proposed rates, including minimization of future revenue deficiencies, value of service, customer impact and understanding, revenue stability, effectiveness in yielding total revenue requirements, historical continuity of rate design, and avoidance of disproportionately large increases for individual customers or classes.

Residential and Small Commercial Service Classifications

Respondent presented a gas marginal customer cost study to show that increased facilities charges are needed to bring residential and small commercial rates in line with marginal costs. Present facilities charges for S.C. 51-Residential and 63-Small Commercial are $3.75 per month and $4.62 per month, respectively, but Respondent's study showed that the marginal customer cost of the service installation for these classes is approximately $21 per month. Respondent's rate design witness testified that considerations of customer impact prevent movement to full marginal cost in residential facilities charges at this time, and that Respondent therefore proposes facilities charges of $10.00 per month for S.C. 51 and $21.00 per month for S.C. 63.

A rate design Staff witness recognized that Respondent's gas marginal customer cost study, by focusing on recent installations of new customers, relies on a base of actual marginal costs. The witness eliminated the minimum distribution system and determined monthly customer costs of $17.00 for S.C. 51 and from $17 to $35 for S.C. 63. He proposed facilities charges of $7.60 for S.C. 51 and $21.00 for S.C. 63.

Respondent's witness testified that proposed S.C. 51 and 63 are designed to recover marginal demand costs in front block commodity charges. The witness stated further that the proposed tailblock charges reflect Respondent's marginal commodity cost of gas, and that tailblock charges are the same in all of Respondent's proposed gas rates except for adjustments to reflect losses for various levels of service.

The rate design Staff witness recommended a two-block rate for S.C. 51 with a tailblock commodity charge of 3¢ per therm higher than that proposed by Respondent. The Staff witness also recommended flattening S.C. 63 and increasing the tailblock commodity charge by 2¢ per therm above Respondent's proposed charge. He testified that a declining block residential rate design, such as that proposed by Respondent, sends a price signal to the typical space-heating customer that gas service is cheaper during the winter peak season.

Respondent's witness testified in rebuttal that customers are likely to be affected more by the total amount of their bills than the amount of the per therm commodity charge, and that a typical residential space-heating customer receives a powerful price signal as his bill increases from the relatively low levels experienced in the fall months to the higher amounts experienced during the winter heating season.

Respondent's witness testified further that the Staff witnesses' proposed flattening of residential and small commercial gas rates would transfer a portion of fixed cost recovery to the tailblock commodity charge. According to Respondent's witness, this would increase the subsidization of non-space-heating customers by space-heating customers and would increase the charges to space-heating customers in winter months.

The Commission finds that in setting rates based on marginal cost, the customer charge should not, as proposed by the Company, enjoy priority over the commodity charge. Such a policy produces inordinately high bill increases for low-use customers and blunts the conservation signal sent by setting commodity charges at marginal costs. The Commission therefore adopts Staff witnesses' proposal to combine the first two blocks of Service Classification 51 and sets the tailblock charge 1.0¢ per therm above the level proposed by Respondent. The proposed facilities charge of $10.00 is excessive and should be reduced to $7.50. Any further reduction from filed rates should come from the front block of the commodity charge.

Commercial and Industrial Service Classifications

Respondent proposes to restructure its commercial and industrial gas rates to classify customers by size of meter installation instead of peak-day demand. Respondent's rate design witness testified that the reclassification would allow facilities charges to be set at levels that more closely represent the widely varying costs of facilities used by commercial and industrial customers.

The rate design Staff witness accepted Respondent's proposed restructuring of commercial and industrial gas rates. He proposed raising the S.C. 64 commodity charge by 1¢ per therm above the S.C. 65 charge on the grounds that demand cost differences in the two rates should be reflected in commodity charges. The Staff witness recognized that a study of marginal demand costs is not available, but stated that smaller customers are likely to be further back on the distribution system and cause marginal demand costs at that level. He also examined seasonal usage patterns and found that the smaller customers on the whole are more coincident with the system peak. He recognized that equivalent commodity charges are necessary on S.C. 6 , 69 and 75 where rate migration poses a problem.

Industrial Power Users' rate design witness recommended rates for S.C. 64, 69, 75 and 85 with the same facilities charges as those proposed by Respondent and lower commodity charges to account for the lower allocation of gas rate increase recommended by the witness for these service classifications.

Respondent's witness testified in rebuttal that the Staff witnesses' proposed rates would disrupt Respondent's rate structure by increasing tailblock charges in S.C. 63 and 64, thereby creating non-cost-justified incentives to transfer among service classifications. He testified that a customer in the upper ranges of consumption under S.C. 63 and 64 would find it cheaper to install an oversized meter in order to obtain a lower commodity charge under S.C. 64 or 65. The witness stated that Respondent's uniform tailblock charges give the customer an incentive to choose the smallest, least expensive metering installation consistent with his needs.

This Staff witness also proposed to eliminate Respondent's guaranteed load factor industrial gas rate, S.C. 69. Respondent proposed a slight reduction in the S.C. 69 facilities charges from the level proposed in the rate as originally filed. This change is reflected in Respondent's Exhibit 6.31, which is Fourth Revised Sheet No. 10 of ILL.C.C. No. 25, Schedule of Rates for Gas Service.

The Commission finds for reasons stated in the discussion of S.C. 24, that the proposed structure for S.C. 69 be accepted at the relative rate levels proposed by Respondent. The adjustment to the facilities charge in S.C. 69 should be accepted.

The Commission is of the opinion that the proposed allocation of the revenue increase among classes is reasonable and supported by marginal cost data. The Company has not proposed large increases for Service Classifications 64, 65, 69, 75 and 85, and therefore these rates should not be reduced. The change in the demand charge for the first 30,000 therms in Service Classification 69 is accepted. All reductions from filed rates should be shared pro rata between Service Classifications 51 and 63. The Commission finds the increase in the Service Classification 63 - Customer Charge, to be excessive and should be reduced to $10. The tailblock commodity charge should be raised 0.5¢ per therm above the filed level. Any further adjustments to meet the revenue requirement should come from the first two blocks of the commodity charge. Service Classification 51 should be adjusted as described above.

FINANCIAL CONDITION AND FINANCING REQUIREMENTS OF RESPONDENT

Much of the evidence presented in this case concerning Respondent's need for an increase in its electric rates related to Respondent's requirements for raising capital to finance its construction program, principally consisting of construction of Clinton Unit No. 1. At December 31, 1981, Respondent had a total capitalization of $2,106,987,000, and net utility plant in service of $1,288,212,000. Respondent's 1981 construction expenditures were $349,515,000.

Respondent's witness testified that Respondent's planned electric utility construction expenditures for the period 1982 through 1984 total $993,287,000. Respondent's planned permanent outside financings during the 1983 period total approximately $270 million if no rate increase is granted. In addition, the balance of short-term debt outstanding at December 31, 1984, would be substantial. Projected financings do not include short-term debt which may be issued by Respondent's subsidiary, Illinois Power Fuel Company, for which Respondent provides credit support.

Respondent's evidence showed that it had an investment in electric construction work in progress at December 31, 1981 of $1,191,374,000, or approximately 57% of its total capitalization, and that electric construction work in progress will increase to $1,533,691,000 at December 31, 1982, at which time it is expected to constitute approximately 63% of total capitalization; and to $1,819,611,000 at December 31, 1983, at which time it is expected to constitute approximately 67% of total capitalization. Respondent stated that its most pressing problem is the need to generate sufficient cash to support construction requirements.

Evidence presented in this proceeding showed that the recent period has been characterized by high interest rates in the capital markets associated with both short-term and permanent financings. The record shows that in 1981 the average yield on double A utility bonds was in the range of 14-16%; and utility preferred stock yields exceeded 13%.

The evidence further indicates that money costs are declining somewhat from these extremely high levels but can be expected to remain at levels which are high by historical standards. In June, 1982, Respondent sold $50 million of guaranteed debentures through its subsidiary Illinois Power Finance Company, N.V., at a cost to Respondent of 14.63%. In July, 1982, $75 million of first mortgage bonds were sold at a cost to Respondent of 14.983%. These cost rates may be compared to cost rates of 11.60% and 12.82% on Respondent's last two issues of long-term debt which occurred in 1980 and to the embedded cost of long-term debt at December 31, 1981, of 8.38%. Without a rate increase, Respondent asserts that it must raise an additional $364,000,000 in new permanent capital through outside financing during 1983 and 1984.

Considerable evidence was presented on the recent and foreseeable financial condition of Respondent. Witnesses on behalf of Respondent addressed the characteristics of financial integrity for a public utility and the significance of financial indicators such as security ratings and financial ratios to the evaluation of a utility's financial condition. Financial integrity was defined as a condition wherein a company has sufficient financial strength to raise needed capital in good and bad markets at reasonable costs and with rates to customers and rates of return to stockholders that are fair.

Investors rely on various measures to evaluate the financial integrity of the firm, including bond and stock ratings, coverage ratios, internal cash generation, level and quality of earnings, dividend stability and growth, and dividend payout ratios among others. Respondent's evidence showed that bond and preferred stock ratings are important criteria of financial integrity which affect the cost of a utility's senior capital, as investors generally require higher interest rates to purchase lower rated senior securities. For example, in 1981, the yields on Moody's triple A rated utility bonds, on a monthly basis, were 45-82 basis points lower than yields on Moody's double A rated utility bonds.

Similarly, Respondent's studies have shown the difference in yields between double A and single A bonds to be 35-45 basis points. Such differences may translate into millions of dollars of additional revenue requirements over the life of a bond issue that carries the lower rating. Bond ratings also affect the utility's access to the capital markets, as many large institutional investors are prohibited from purchasing senior securities which do not have high quality ratings.

A rating of triple A or double A is considered to be a high quality rating. The determination of bond ratings is in turn influenced by data such as coverage ratios, internal cash generation and level and quality of earnings. Utilities whose earnings available for common includes a significant portion of AFUDC are considered to have lower quality earnings.

The evidence showed that after being rated double A by both of the major security rating agencies for a number of years, Respondent's first mortgage bonds and preferred stock were downgraded to AA- by one of the agencies in April, 1982. Also the other agency has assigned Respondent's senior securities a rating of Aa3, which is the lowest rating in the AA category. Respondent states that its financial condition has been declining over a number of years as evidenced by deteriorating financial statistics culminating in the downgrading of its securities; and that its securities may be further downgraded unless its financial condition is improved. Respondent's witness testified that Respondent's financial statistics must be improved above 1982 levels in order to avoid further downgradings.

Respondent presented evidence on its historical performance compared to double A rated utilities and its forecasted performance as measured by certain financial data which were identified as indicators of the above measures of financial integrity. Historical and forecasted data under various rate increase scenarios was presented with respect to the following statistics: (1) interest coverage before income taxes, including AFUDC (a measure of interest coverage); (2) interest coverage before income taxes, excluding AFUDC (a measure of cash coverage of interest obligations); (3) internal cash generation as a percent of additions to utility plant (a measure of internal cash generation and cash flow); (4) AFUDC as a percent of earnings applicable to common stock (a measure of quality of earnings); (5) return on average common stock equity (a measure of return to the common stockholders); and (6) ratio of total debt to total capitalization plus notes payable (a measure of capital ratio flexibility). Respondent also showed financial goals which it has established with respect to each of these statistics in order to maintain its financial integrity and its relative credit standing compared to double A rated utilities. Respondent identified these goals as goals for a double A rating.

Data compiled by Respondent's witness showed that Respondent's financial statistics were worse over the five-year period 1977-1981 than the average for the twenty other utilities carrying double A first mortgage bond ratings according to both major rating services during the same period, and that in 1981, Respondent's performance was worse than the average for the double A utilities in every statistic except total debt as a percentage of total capitalization plus notes payable. Further, Respondent's performance with respect to four of the six ratios was worse in 1981 than for the entire five-year period, indicating a deteriorating trend.

Respondent's interest coverage ratio excluding AFUDC for the five-year period was 60 basis points below the average for double A utilities. Over the five-year period, Respondent's internal cash generation as a percentage of utility plant was only one-half of the ratio achieved by the double A utilities as a group. In

1981, internal cash generation was 56.7% for the double A utilities but only 19.3% for Respondent. While the double A utilities, as a group, improved internal cash generation from 54.5% in 1977 to 56.7% in 1981, Respondent's internal cash generation fell from 31.8% to 19.3%. AFUDC as a percent of earnings was 48% for Respondent versus only 28% for the double A utilities over the five-year period, and 57.1% versus only 29.4% for the double A utilities in 1981.

Respondent presented forecasts of its financial performance as measured by the six financial statistics during the period 1982 through June 30, 1984 if it receives no rate increase. Forecasted data presented by Respondent showed a general and severe decline in Respondent's financial integrity, and inability to maintain a position comparable to that of double A rated utilities. The evidence showed particularly poor performance with respect to those statistics relating to Respondent's cash position, including interest coverage excluding AFUDC, internal cash generation as a percent of additions to utility plant, and AFUDC as a percent of earnings.

Respondent also presented historical and forecasted information on internal cash generation and cash flow per share. All of this evidence showed Respondent's financial position would continue to decline during the period studied. Respondent expressed concern that failure to improve its financial statistics and financial condition over 1981-1982 levels would result in further downgrading of its securities which would affect its ability to raise capital and its cost of capital

Respondent's evidence showed that the market price of its stock has fallen substantially over time on a nominal-dollar basis and, in particular, on an inflation-adjusted basis; and that the market price-to-book value ratio of its common stock has also fallen over time. In 1980 and 1981, Respondent sold 10,600,045 shares of new common stock at an average price below average book value; this reduced the book value of existing stockholders' investment in Respondent by $50.6 million. In March, 1982, Respondent sold 4 million shares of new common stock at a price less than book value.

Illinois Power's evidence presented in this proceeding shows that Respondent faces continued heavy construction and financing requirements over the next two years, and provides a basis for serious concern over Respondent's ability to meet its capital requirements on reasonable terms. Although capital markets may become somewhat more hospitable in the near term than in 1981, the record suggests the need for concern with respect to Respondent's wherewithal to withstand any adverse developments affecting its ability to raise capital. The record demonstrates that Respondent's financial performance during the recent past and forecast for the near term, as depicted by numerous measures including the recent downgrading of Respondent's senior securities, is inferior to that of utilities with high quality bond and preferred stock ratings.

The People contend that if the Commission believes that Respondent's approach to measuring financial health through the six goals is reliable, it should use different goals or standards so as to avoid granting more of an increase than is necessary during a period of substantial unemployment and recession. Only 50 to 65% of the rate increase can be justified by reliance on these six financial ratios. An award of 63.5% of the increase, 68% of the incremental CWIP and a 15.3% return on equity allows Respondent to essentially meet the 1981 average for the Double A companies for four of the ratios and to materially improve its ratios for internal cash generation (17.1% in 1982 up to 34.9% in 1983) and AFUDC as a percent of earnings (56.7% in 1982 down to 41.2% in 1983).

The Commission has reviewed all the financial statistics, historical and forecasted, presented by witnesses in this case relating to Respondent's financial performance and that of other utilities as well as the evidence presented on Respondent's construction and financing requirements and general economic and financial market conditions. It is apparent from the evidence that Respondent has very substantial financing requirements during the next two years and will be required to raise a large amount of capital in relation to its existing capitalization and that Respondent's ability to do this on reasonable terms will be seriously impaired unless its financial integrity is maintained at reasonable levels. Illinois Power's statistical data and other information presented indicates that Respondent's financial condition has been deteriorating during the last several years. The Commission has fully evaluated all this evidence and its specific findings and conclusions hereinafter set forth in relation to rate base, operating income and rate of return all reflect due consideration of this evidence.

The Commission intends the authorized rates granted in this Order to be the minimum it could allow in meeting its responsibilities, and emphasizes that Illinois Power has the burden of reducing its expenditures to increase its internal cash generation. This obligation of the utility the Commission takes very seriously. Respondent must reduce its expenses and hence by its own actions improve its internal cash position. In effecting these expense reductions, Respondent will directly benefit its customers considering the extent of its construction program and current economic conditions. Respondent should file detailed expense reduction plans with the Commission's Chief Clerk within sixty (60) days of the date of this Order.

TEST YEAR

Respondent proposes use of a fully forecasted 1983 test year in this proceeding. Respondent submitted forecasted information for use as the basis for test year data which was developed by Respondent using its corporate computer model. Respondent's witness presented testimony and exhibits concerning Respondent's corporate model and the methodologies and procedures used to develop the forecast. He also presented detailed statements of the major assumptions used in preparation of the forecasted information.

Respondent, in its evidence, submitted audited information from an independent auditing firm required by General Order 210 in connection with use of its forecasted test year, including: (1) an opinion from a certified public accounting firm evidencing compliance with guidelines for financial forecasts of the American Institute of Certified Public Accountants; (2) a statement that the forecasted information presented was reasonable, reliable and made in good faith and that the assumptions and methodologies used to prepare the forecasted information were the same assumptions and methodologies used to prepare forecasted information for management and for distribution to the financial community; (3) data for the "historical" (1981) and "current" (1982) periods; and (4) during the course of the proceedings, actual results through July 31, 1982, and comparisons of the forecasted information to actual results.

Respondent's 1983 test year data reflects the effects of significant cost reduction efforts in 1981, 1982 and 1983. Respondent's witnesses explained that Respondent established a cost reduction task force in 1981 to identify operating and construction expenditures which could be eliminated or deferred, and possible reductions in inventories. Respondent's witnesses testified that in 1981 and 1982, the task force identified reductions of $50,000,000 in cash requirements, including a $5,000,000 reduction in operating expenses, a $25,000,000 reduction in fuel inventories, and a $20,000,000 reduction in construction expenditures. For 1983, the task force identified further expenditure reductions of approximately $29,000,000, including $4,800,000 of reductions in operating and maintenance expenses and $24,000,000 of reductions in construction expenditures.

Witnesses for Respondent testified that the 1983 cost reductions are being achieved through layoffs of present employees and elimination of presently vacant positions, deferral of management salary increases for at least six months, a freeze on hiring of new engineers, reduction in planned construction expenditures, retirement of two peaking units and other measures. Respondent reflected the cost reductions in its proposed 1983 rate base and operating income statements. Respondent's witness testified that the work of the cost reduction task force is an ongoing effort with no stated termination date.

The People of the State of Illinois, Town of Normal and City of Galesburg ("Normal and Galesburg") and the Urbana School District contend that Illinois Power's cost reduction task force was established to identify, eliminate, reduce or defer, inter alia, operating expenses. The burden is on the Company to justify the expenses it is claiming. This burden is increased during a time of recession and high unemployment such as that now being experienced. These Intervenors claim that Respondent did not take significant steps at cost reduction or confirm that the efforts of the task force were effective.

A member of the Economics and Rates Department of the Commission Staff analyzed the electric and gas sales forecasts underlying Respondent's financial forecast. He concluded that Respondent's overall approach to forecasts was a sound one and that the high degree of disaggregation would help Respondent to foresee new trends before the impact on actual sales appeared. He also concluded that Respondent devoted considerable effort to obtaining a sound data base for the forecast. The witness also noted that use of a current test year would most likely understate the sales level during the tenure of the proposed rates. The witness concluded that the sales forecast showed a relatively greater revenue deficiency for the electric utility than the gas utility.

Based on a review of all the data presented by Respondent, both historical and forecasted, the Commission is of the opinion and finds that the twelve month period ending December 31, 1983 is the appropriate test year which should be used for purposes of establishing rates in this proceeding.

RATE BASE

Respondent proposed the following net original cost and fair value rate bases for the 1983 test year:

1983 Original Cost Rate Base

Item	Electric Amount (000)	Gas Amount (000)	Combined Amount (000)
Original Cost of Plant in service	$1,666,995	$ 383,308	$2,050,303
Reserve for depreciation	(630,369)	(112,863)	(743,232)
Net original cost of plant in service	$1,036,626	$ 270,445	$1,307,071
Rate base adjustments			
Land and land rights held for future use	11,143	33	11,176
Investment in IP Gas Supply Company	-	3,957	3,957
Construction work in progress	875,000	-	875,000
Materials and supplies exclusive of merchandise	23,727	2,922	26,649

Electric fuel inventory	46,931	-	46,931
Gas and propane in storage	-	46,953	46,953
Accumulated provision for deferred income taxes	(193,419)	(30,513)	(223,932)
Contributions in aid of construction	(12,221)	(6,525)	(18,746)
Customer advances for construction	(1,470)	(2,278)	(3,748)
Total rate base adjustments	749,691	14,549	764,240
Net original cost rate base	$1,786,317	$ 284,994	$2,071,311

1983 Fair Value Rate Base

Electric Utility

Item	Amount (000)		Adjusted Amount (000)
Trended cost less depreciation of plant in service	$2,385,650		
Weighting		.25	$ 596,413
Net original cost of plant in service	1,036,626		
Weighting		.75	777,470
Fair value of plant in service			1,373,883
Total rate base adjustments			749,691
Fair value rate base			$2,123,574

Gas Utility

Item	Amount (000)		Adjusted Amount (000)
Trended cost less depreciation of plant in service	$ 706,550		
Weighting		.25	$ 176,638
Net original cost of plant in service	270,446		
Weighting		.75	202,834
Fair value of plant in service			379,472
Total rate base adjustments			14,549
Fair value rate base			$ 394,021

Combined

Item	Amount (000)		Amount (000)
Trended cost less depreciation of plant in service	$3,092,200		
Weighting		.25	$ 773,050
Net original cost of plant in service	1,307,071		
Weighting		.75	980,304
Fair value of plant in service			1,753,354
Total rate base adjustments			764,240
Fair value rate base			$2,517,594

The amounts shown above are as set forth on Respondent's Exhibits 2.57-2.58 and 9.30-9.31 Revised and as modified by data set forth in IP Exhibit 2.60 which showed the estimated 1983 effect on Respondent of the Tax Equity and Fiscal Responsibility Act of 1982. These were further adjusted by Respondent on late filed IP Exhibit 9.34 which reflected the exclusion of Mt. Carmel Public Utility Co. from rate base, the addition of Mt. Carmel as a wholesale electric customer and the exclusion of Mt. Carmel customers who would have been served as retail electric and gas customers by Illinois Power, as of December 3, 1982.

The amounts specified for the rate base adjustments (land and land rights held for future use, investment in IP Gas Supply Company, materials and supplies, electric fuel inventory, gas and propane in storage, accumulated provision for deferred income taxes, contributions in aid of construction, and customer advances for construction), other than construction work in progress, are the averages of the thirteen monthly balances for each item. The proposed electric and gas rate bases also reflect the following additional adjustments: (1) removal of elements attributable to Respondent's appliance leasing business; (2) removal of depreciation attributable to contributed property; (3) exclusion of land held for future use which does not have a definite in-service date on or before December 31, 1992; (4) determination of the accumulated provision for deferred income taxes using a method of computation, proposed by a Staff witness, intended to comply with Internal Revenue Service requirements; and (5) reduction of electric rate base by $2,076,000 and gas rate base by $2,048,000 to reflect the impact on plant in service of anticipated 1983 cost reductions identified by Respondent's cost reduction task force.

Fair Value Rate Base

A witness in a valuation engineering firm, testifying on behalf of Respondent, presented evidence on the trended original cost of plant in service at December 31, 1982 and December 31, 1983. The witness testified that he determined the current cost of Respondent's electric and gas utility plant at September 30, 1981 using a trending method based on the Handy-Whitman Index, the indices maintained by the Bureau of Labor Statistics and Stevens Valuation Quarterly for types of equipment classified in general plant accounts 391-398, and, where necessary, indices specific to Respondent which he prepared. He testified that a trending method was used because it is the fastest and least expensive method to estimate current cost and has the advantage of starting from recorded original cost. Custom indices specific to Respondent were developed to obtain greater precision on accounts where indices based on national, regional or local averages might not properly reflect Respondent's experience.

The data used to compile the specific indices was taken from the books and records of account maintained by Respondent. The witness testified that he added net additions and retirements at original cost, as projected by Respondent for the periods September 30, 1981 to December 31, 1982 and December 31, 1983, to the trended cost of plant in service at September 30, 1981, to determine trended cost at December 31, 1982 and 1983. He further testified that depreciation was deducted so that the remaining trended cost was equivalent to the ratio of net original cost to original cost. This method, which the Commission has utilized in recent fair value rate cases, produces a larger depreciation deduction than would a more accurate depreciation study, and therefore results in a conservative value for trended cost less depreciation.

The witness, on IP Exhibit 3.3 and 3.5, presented the following summary of trended cost and trended cost less depreciation at December 31, 1983:

Electric Utility

	Trended Cost (millions)	Trended Cost Less Depreciation (millions)
Intangible plant	$ .5	$ .5
Production plant	1,930.5	1,206.9
Transmission plant	537.3	328.5
Distribution plant	1,340.7	760.1
General plant	122.6	66.5
Total depreciable plant	$3,931.1	$2,360.0
Land (original cost)		29.1
Total		$2,391.6

Gas Utility

	Trended Cost (millions)	Trended Cost Less Depreciation (millions)*
Intangible plant	$ .1	$ -
Manufactured gas production plant	16.1	
Underground storage plant	53.6	
Transmission plant	148.0	
Distribution plant	738.5	
General plant	64.5	
Total depreciable plant	$1,020.7	$ 706.1
Land (original cost)		5.4
Total		$ 711.5

The witness testified that he included hydraulic production plant, which is fully depreciated, and land and land rights, at original cost; excluded leased property on customer premises, which the Commission has previously excluded from rate base; and made appropriate allocations of property to the gas utility.

The Commission is of the opinion and finds that the trended cost and the trended cost less depreciation as presented by Respondent's witness is reasonable and should be adopted for purposes of this proceeding.

Respondent's witness testified that the value of trended cost less depreciation used by Respondent to develop the 1983 fair value rate base was the average of trended cost less depreciation at December 31, 1982 and December 31, 1983. The witness presented a fair value rate base determined on a weighting of 75% net original cost and 25% trended cost less depreciation, which has been used by the Commission in recent fair value decisions.

Based on all the evidence and considerations, including the trended cost less depreciation of Respondent's electric and gas

* Gas utility depreciation is not maintained by function.

utility plant at December 31, 1982 and December 31, 1983; the net original cost of utility plant for the 1983 test year; the weighting utilized by Respondent's witness; and the rate base adjustments discussed in this Order including the determination with respect to electric construction work in progresss as hereinafter discussed, the Commission is of the opinion and finds that Respondent's net original cost and fair value rate bases for the 1983 test year which should be used for purposes of this proceeding are as follows:

Original Cost Rate Base

Electric Utility:	$1,536,310,000
Gas Utility:	$ 284,994,000
Combined:	$1,821,304,000

Fair Value Rate Base

Electric Utility:	$1,873,567,000
Gas Utility:	$ 394,021,000
Combined:	$2,267,588,000

OPERATING REVENUES, EXPENSES AND INCOME

Respondent presented the following operating income statement for the 1983 test year at proposed rates:

1983 Operating Income Statement

Item	Electric Amount (000)	Gas Amount (000)	Combined Amount (000)
Operating revenues*	$895,603	$571,400	$1,467,003
Operating expenses			
Fuel for electric plants	312,237	-	312,237
Gas purchased for resale	-	427,161	427,161
Power purchased for resale	31,277	-	31,277
Power interchanged-net			
Capacity	(4,513)	-	(4,513)
Energy	(38,985)	-	(38,985)
Operation and maintenance	115,888	40,587	156,475
Depreciation and amortization	52,799	13,908	66,707
Taxes other than income taxes	56,493	22,170	78,663
Federal income taxes-current	86,587	22,730	109,317
State income taxes-current	16,643	3,567	20,210
Provision for deferred income taxes	32,168	8,378	40,546
Income taxes deferred in prior years	(10,068)	(7,678)	(17,746)
Investment tax credit deferred-net	22,908	840	23,748
Total operating expenses	673,434	531,663	1,205,097
Operating income	$222,169	$ 39,737	$ 261,906

* Includes add on taxes

The amounts shown are as set forth on Respondent's Exhibits 2.57-2.58 and as modified by data set forth on IP Exhibit 2.60 which showed the estimated 1983 effect on Respondent of the Tax Equity and Fiscal Responsibility Act of 1982. These were further adjusted by Respondent on late filed IP Exhibit 9.34 which reflected the exclusion of Mt. Carmel Public Utility Co. from rate base, the

addition of Mt. Carmel as a wholesale electric customer and the exclusion of Mt. Carmel customers who would have been served as retail electric and gas customers by Illinois Power, as of December 3, 1982.

Respondent's proposed operating income statement reflected the following adjustments: (1) operating expenses were adjusted to exclude membership dues and fees in certain civic and social clubs and the cost of analysis of proposed legislation and certain public information costs; (2) operating expenses and operating revenues and return attributable to Respondent's appliance leasing business were removed; (3) operating expenses and return were adjusted to remove depreciation attributable to contributed property; (4) operating revenues and operating expenses and return were reduced to reflect the removal of the two percent excess State Public Utility Tax and various Municipal Utility Taxes; (5) operating expenses and return were adjusted to reflect income tax allocation procedures recommended by a Staff witness on behalf of the Commission's Accounts and Finance Department; (6) 1983 electric operation and maintenance expense was reduced by $3,654,000 and 1983 gas operation and maintenance expense was reduced by $1,161,000 to reflect 1983 expenditure reductions identified by Respondent's cost reduction task force; and (7) operating revenues and operating expenses and return were adjusted to reflect the impact of certain modifications to the design of industrial electric and gas rates which were proposed during the proceedings.

Respondent's proposed budget for 1983 advertising expenses is $514,000. The Company's advertising budget was cut from $468,703 in 1981 to $236,000 in 1982 because of Illinois Power's cash flow problems. Normal and Galesburg contend that Respondent's Supervisor of Advertising and Media Production had not and could not assess the effectiveness of the advertising program. The People and the Urbana School District claim that the advertising expenditures have not been justified as a benefit to subscribers. The proposed 1983 advertising budget returns to the 1981 level plus inflation. The Commission is of the opinion that there is no justification for returning to the 1981 level when the cash flow problem still exists, a recession is in progress, and there is no evidence that the increased advertising coverage purchased by that higher 1981 level was any more effective than the coverage purchased at the 1982 level. Therefore, the Commission allows no more than $236,000 for advertising in the test year.

Normal and Galesburg argued that the 1982 Lincoln Continental automobile provided the Respondent's chief executive officer and Illinois Power's use of a Springfield apartment were not justified. The evidence shows an insufficient use of the apartment to warrant this expenditure and accordingly it is disallowed. It is the Commission's opinion that this luxury automobile creates an appearance of indifference to the economic circumstances of Illinois Power's ratepayers. Respondent's operating income and rate base should be adjusted to replace the 1982 Lincoln Continental automobile with a fleet car.

Proposed Revisions to Gas Utility Depreciation Rates

Respondent's proposed test year gas utility depreciation and amortization expense was based on revisions to its gas utility depreciation rates for which it seeks approval in this proceeding. Based on the recommendations of a valuation engineer who testified in its behalf, Respondent proposed the following revisions to gas depreciation rates:

Gas Utility Depreciation Rates

Function	Current Rate	Proposed Rate
Production	4.25%	4.08%
Underground storage--		
Account 350	4.00	2.34
Account 358	4.00	2.51
Other	4.00	2.49
Transmission	2.70	2.95
Distribution	2.70/6.00	4.19
General Plant--		
Account 390	4.24	2.97
Accounts 392 & 396	16.00	6.11
Other	4.24	3.10
Total Gas Plant	2.95	3.95

The Commission last revised Respondent's gas depreciation rates in Docket No. 50651 (December 22, 1964).

Respondent's proposed depreciation rates are based on two components: (1) average service lives for plant in service; and (2) an allowance for negative salvage. To determine the first component, Respondent's witness made an analysis of average service lives by function based on Illinois Power's property records, the use of the simulated plant balance and retirement rate methods, and special studies for those accounts such as underground storage in which data on retirements are too limited to permit an actuarial or simulated analysis. The witness used Equal Life Group ("ELG") accruals to match depreciation to actual consumption of capital in the transmission and distribution functions. The witness testified that ELG accruals are recommended as the best way to match depreciation to the actual consumption of capital plant because this method avoids under-accrual and over-accrual for individual units at retirement.

The witness identified the second component of the proposed depreciation rates, negative salvage, as the excess cost of abandoning or removing retired property over its salvage value. He testified that most negative salvage occurs in underground gas facilities because they are not economically salvageable. Mains and services are normally abandoned rather than salvaged, and these abandonments cause the Company to incur such costs as excavating, evacuating gas, capping, backfilling and frequently repaving. These costs generally are not offset by any salvaged material. The witness further testified that recovery of negative salvage through depreciation is a generally accepted accounting procedure and conforms to the Uniform System of Accounts.

The witness examined Respondent's negative salvage experience over the five year period 1976-1980 to determine the appropriate negative salvage components of Respondent's gas depreciation rates. The witness testified that the total dollar amount of cost of removal experienced by Respondent increased from $561,000 in 1976 to $745,000 in 1980, and that negative salvage averaged 18.5% during this period and ranged annually between 13.8% and 23.7% of retired plant. Respondent's witness utilized a negative salvage rate of 17% for the gas utility as a conservative estimate because it was exceeded in all but one of the five years 1976-1980 and was lower than the five year average of 18.5%.

Since Respondent does not classify salvage by account for the gas utility (and is not required by the Uniform System of Accounts for Gas Utilities, General Order 179, to do so), the witness made an allocation of total gas utility negative salvage expense to the various functions. However, the witness testified that no negative salvage expense was allocated to land rights and cushion gas asso-

ciated with underground storage nor to general equipment classified in Accounts 391-398 since these assets are not subject to any significant cost of removal at retirement. The witness allocated a negative salvage expense based on the total gas utility rate of 17% to all accounts other than those just named in proportion to depreciation expense for each account.

A member of the Commission's Engineering Department, now deceased but who during his tenure served this Commission with distinction, presented testimony concerning the proposed depreciation rates. The Staff witness did not challenge the determination of the average service lives used in the proposed depreciation rates. However, he testified that in the Staff's view, additional information relating to the negative salvage values by functional groups or individual accounts needed to be provided, as well as more specific information on the Respondent's negative salvage experience by function for the period studied by Respondent's witness.

In response to the Staff witnesses' request, Illinois Power's witness reviewed the negative salvage experience by function by means of an examination of retirement work orders for 1976-1981 to determine salvage and cost of removal for each functional classification. Using the actual data on negative salvage by function for the five year period 1976-1980, the witness determined an appropriate negative salvage component for each function. The witness testified that the combination of the component to recover the original investment (based on average service lives) and the component for negative salvage results in the proposed depreciation rates. The witness also testified that the examination of work orders showed no extraordinary retirements or unusual costs of removal during the five year period which might make that period atypical.

Respondent's witness also reviewed Respondent's 1981 experience. He testified that in 1981, the cost of removal was higher than it had ever been before, $829,000. However, net salvage was positive for the first time in the last eleven years. Respondent's witness stated that the positive net salvage occurred because Respondent was reimbursed $512,000, of which approximately $11,000 represented reimbursement for cost of removal, by the State of Illinois, for gas mains abandoned in connection with the construction of I-270 near East St. Louis.

The $501,000 reimbursement net of cost of removal was not actually salvage but rather payment for the cost of replacing the abandoned mains with new mains. The witness testified that reimbursements of this magnitude have not been experienced in the recent past and are not foreseen in the future, and that if these reimbursements are not considered, the net negative salvage for 1981 is $485,000, an amount which is comparable to that experienced in 1976-1980. Respondent's witness testified that inclusion of 1981 data in his study would still indicate an overall negative salvage requirement of 17% to be a conservative estimate.

The Commission has reviewed the testimony and exhibits of Respondent's witness pertaining to the recommended revisions to gas utility depreciation rates. The Commission is of the opinion based on this evidence that the proposed gas utility depreciation rates are reasonable and appropriate and should be approved by the Commission pursuant to Section 14 of the Illinois Public Utilities Act; and that the proposed gas utility depreciation rates should be used for ratemaking purposes in this proceeding.

Economic Recovery Tax Act

Respondent presented evidence for the tax period reflecting the tax law changes under the Economic Recovery Tax Act of 1981 ("ERTA"). Any utility which wishes to avail itself of certain tax

benefits in ERTA must be permitted to fully normalize Investment Tax Credits ("ITC") and the deductions under the Accelerated Cost Recovery System ("ACRS"). Any other accounting and ratemaking treatment will result in the loss of these benefits to Respondent and, ultimately, to its ratepayers. Respondent has utilized the proper accounting in this proceeding and has been permitted to recover in the rates authorized herein the full amount necessary to comply with this normalization requirement. Respondent should continue to conform with all applicable accounting requirements of ERTA, including the normalization of ITC and ACRS benefits so as to minimize its tax liability.

Based on all the foregoing considerations, the Commission is of the opinion and finds the electric and gas operating income, with adjustments, for the 1983 test year which should be utilized for ratemaking purposes in this proceeding is as follows:

Operating Income

Electric Utility:	$184,050,000
Gas Utility:	$ 34,142,000
Combined:	$218,192,000

Based on the original cost and fair value rate bases and operating income statement for the 1983 test year adopted by the Commission for purposes of this proceeding, Respondent's pro forma return for the 1983 test year at present rates is 11.98% on original cost electric rate base, 9.89% on fair value electric rate base, 11.98% on original cost gas rate base, and 8.67% on fair value gas rate base.

CONSTRUCTION WORK IN PROGRESS

Respondent presented a considerable amount of evidence in support of its proposal to include in rate base an additional $500 million of construction work in progress resulting in a total amount of construction work in progress ("CWIP") in rate base of $875 million, and to cease capitalization of an allowance for funds used during construction ("AFUDC") on this amount.

The Commission has in previous cases involving proposals to include CWIP in rate base, including the last three Illinois Power Company rate orders, Docket Nos. 76-0435 (June 15, 1977), 79-0071 (November 28, 1979) and 80-0544 (July 1, 1981), developed and applied criteria for determining when CWIP may appropriately be included in rate base. The Commission stated as follows in its Order in Docket No. 80-0544 at p. 33:

> "The Commission views the investment of funds in CWIP as used and useful to the benefit of the customer which may be included as a component of the rate base when, pursuant to a certificate of convenience and necessity granted by the Commission for construction of such a plant, the investment grows to a point where its significance is so great that it could impair financing. To what extent such investment, if any, should be included in the rate base for a particular public utility, must, however, be determined by the specific circumstances in each rate proceeding and will be considered by the Commission on a case-by-case basis."

The Commission, pursuant to The Illinois Public Utilities Act, has the discretion to include a portion of Respondent's construction work in progress in rate base if and when the evidence in the record supports such inclusion.
(See: Citizens for a Better Environment, v. Illinois Commerce Commission, 103 Ill. App. 3d 133).

In support of its proposal to include an additional amount of CWIP in rate base, Respondent presented evidence on the size of its investment in CWIP in relation to its total capitalization; and on the impact of this large balance of CWIP on its financial condition and ability to raise additional capital. Respondent also offered evidence on the comparative revenue requirements resulting from inclusion of an amount of CWIP in rate base as opposed to capitalization of AFUDC on that amount, and on other benefits of including CWIP in rate base from the point of view of both the utility and the ratepayer including reduction in the cost of and total revenue requirements associated with the project under consideration. Respondent also presented evidence to show the effect on its financial condition of including varying amounts of CWIP in rate base.

The record shows that at December 31, 1981, Respondent's investment in electric CWIP was $1,191,374,000 constituting approximately 57% of total permanent capitalization at that date. Respondent's investment in electric CWIP as a percent of total capitalization has increased from 40% at December 31, 1979 and 46% at December 31, 1980; and Respondent projects that its investment in electric CWIP will be $1,533,691,000, or approximately 63% of total capitalization, at December 31, 1982, and will be $1,819,611,000, or approximately 67% of total capitalization, by December 31, 1983.

These amounts of electric CWIP may be compared to Respondent's balance of net original cost of utility plant (electric and gas) in service which was $1,288,212,000 at December 31, 1981, and is projected to be $1,304,522,000 at December 31, 1982. Electric CWIP was 53% of net electric utility plant (including construction work in progress) at December 31, 1981 and is projected to grow to 59% of net electric utility plant at December 31, 1982 and to 63% of net electric utility plant at December 31, 1983.

A witness for Respondent testified on the effect of Illinois Power's large balance of electric CWIP on Respondent's financial condition and ability to raise capital. The witness testified that the lack of a current cash return on a significant portion of Respondent's invested capital has resulted in deterioration of its ability to service adequately its outstanding capital and to raise additional capital for its current construction program. Due to the disparity between total assets and assets producing a cash return, Respondent's cash earnings from operations have been insufficient in nine of the last ten years to pay fixed charges and a reasonable common dividend.

He testified that the gap between operating income and interest, preferred dividend and common dividend requirements has grown from $6.6 million in 1976 to $46.7 million in 1981 and is projected to be $51.8 million for 1982. This requires Respondent to raise additional capital in order to have the funds needed to service existing capital, which the witness testified dilutes earnings and the value of present equity holders' investment and is viewed as a sign of a financially unsound enterprise by prospective investors, since a healthy firm generates sufficient income from its operations to service its outstanding capital without having to sell additional securities for this purpose.

The Company witness testified that continued issuance of first mortgage bonds and preferred stock to finance construction which earns no current cash return may cause coverage ratios specified in Respondent's mortgage indenture and incorporation documents to fall to near the levels at which no additional bonds or preferred stock can be issued. This problem is exacerbated by the need to sell securities during periods of high inflation and interest rates. New fixed-income securities must be sold at incremental costs which are much higher than the existing embedded cost of capital. Interest and preferred dividend requirements are increased substantially without a corresponding increase in cash earnings. As a result, coverage ratios fall to unacceptable levels.

Respondent's evidence showed that its interest coverage ratio calculated in accordance with its mortgage indenture was 3.73 times as recently as 1975 but has fallen to 2.58 times in 1981 and would fall to 2.23 times in 1983, which would be a new low. Respondent is prohibited from selling additional first mortgage bonds if interest obligations on bonds outstanding and those proposed to be sold would cause the coverage ratio to fall below 2.00 times.

Respondent's witness also testified that as the balance of CWIP increases, Respondent's internal generation of cash for construction requirements declines, due in substantial part to the fact that current depreciation, which represents cash flow, is based on the original cost of plant in service that was built in the past at costs much lower than the costs of facilities currently being installed, and is therefore, insufficient to fund current construction. Retained earnings are also inadequate for this purpose.

Respondent's evidence indicates that its internal cash generation as a percent of additions to utility plant has declined from 31.8% in 1977 to 19.3% in 1981 and is forecasted to decline to 11.9% for 1983 and to 6.8% for the 12 months ending June 30, 1984. Reduced internal cash generation of construction requirements increases Respondent's reliance on the external capital markets. As a utility must raise more and more capital externally at incrementally higher rates, embedded costs of capital are raised, interest and preferred dividend requirements increase and coverage ratios further decline. Illinois Power's evidence shows that Respondent has experienced all these impacts. In addition, the ability of the firm with substantial capital requirement to stay out of the capital markets when conditions are unfavorable is reduced.

Respondent's witness testified that if CWIP is included in rate base, Respondent obtains additional cash return which reduces its need to issue additional securities to obtain funds to pay interest and dividends. Interest coverage ratios are improved due to the greater cash earnings and reduced interest requirements since fewer securities are issued.

Respondent also presented evidence pertaining to the growth in the AFUDC component of its earnings. Respondent's witness testified that utilities whose earnings available for common include a significant portion of AFUDC are considered to have lower quality earnings. Respondent's evidence showed that its balance of AFUDC as a percent of earnings available for common increased from 33.4% in 1977 to 57.1% in 1981 and is projected to increase to 68.5% in 1983 and to 71.6% for the twelve months ending June 30, 1984. Respondent's evidence indicates that its 1981 ratio of AFUDC as a percent of earnings was higher than that of any of the 20 double A utilities analyzed by Respondent for comparative purposes.

Respondent also presented evidence indicating that Respondent's large investment in CWIP may result in its securities being further downgraded by security rating agencies. Respondent's first mortgage bonds and preferred stock were downgraded from AA to AA- by one of the major rating agencies in April 1982 and are rated Aa3, the lowest rating in the AA category, by the other major rating agency. Respondent's witness testified that the downgrading will result in higher costs for future issues of senior securities.

There is evidence to show that these agencies rely on numerous factors such as financial indicators of internal cash generation; fixed charge coverages, including and excluding AFUDC; AFUDC ratio; debt ratios, and construction program and financing requirements, including ratios of interest coverage before income taxes, excluding AFUDC; internal cash generation as a percent of additions to utility

plant; and AFUDC as a percent of earnings applicable to common. These are ratios which are specifically affected by the regulatory treatment of CWIP. Respondent's evidence showed that it is experiencing declines in all these measures.

Evidence was presented by Illinois Power to show that in recent years, a number of factors have combined to create a more hostile environment for utility operations thereby increasing the risks of the utility business perceived by investors. High levels of inflation, high interest rates, longer and more capital-intensive construction periods, increased environmental and other regulatory restrictions on utility operations and construction, and rapid fuel price escalation, have increased the risk of investments in utilities including Respondent as evidenced by increasingly higher capital costs. In the more difficult capital markets, the adequacy of the utility's level of financial integrity is of particular importance.

Illinois Power presented evidence comparing its important financial statistics to those of double A rated utilities over the period 1977-1981. These data indicated Respondent's financial condition to be deteriorating during a period of heavy construction expenditures and financing requirements, and showed its historical financial performance to be significantly worse than that of double A rated utilities. Respondent also presented evidence for the purpose of evaluating the effect on its financial ratios and financial condition of including varying additional amounts of construction work in progress in rate base.

Respondent presented projections of financial ratios for the period January, 1983 through June 30, 1984, under various assumptions as to the amount of rate increase allowed in this proceeding including the amount of CWIP in rate base. Respondent focused attention on financial ratios relating to internal cash generation and cash flow which are affected by the treatment of CWIP since, as Respondent's witness testified, Respondent's principal problem is the need to support is construction program. Respondent's evidence showed that its financial ratios would improve with greater amounts of CWIP in rate base but that only with the full amount of CWIP proposed by Respondent would Respondent be able to meet its financial goals for the double A bond rating, or the 5-year averages for double A utilities, in 1983 and 1984.

Respondent also presented an analysis of the extent to which operating income would be sufficient to cover fixed charges and common dividend requirements in 1983 under the various assumptions modeled. This analysis indicated that if a rate increase were granted without inclusion of additional CWIP in rate base, operating income would fall short by some $57.9 million of covering capital service requirements, assuming no increase in the current common stock dividend.

Forecasts of Respondent's financial condition were also prepared by members of the Commission's Accounts and Finance Department using the Commission's Regulatory Analysis computer model. These analyses projected numerous financial ratios such as interest coverage ratio before tax including AFUDC, interest coverage ratio before tax excluding AFUDC, coverage of long-term debt excluding AFUDC, cash dividend coverage, internal funds as percent of construction expenditures, internal cash generation as percent of debt, AFUDC as percent of earnings for common, and cash flow per share, under various assumptions as to the amount of rate increase allowed Respondent in this proceeding, including the amount of CWIP included in rate base. Staff witnesses' projections showed that if Respondent is granted a rate increase without inclusion of additional CWIP in rate base, these financial ratios would improve in the post 1983 period.

Respondent also showed that its proposed amount of $875 million of CWIP to be included in rate base would represent only 57% of the total CWIP at December 31, 1982 and approximately 48% of the total CWIP at December 31, 1983. Respondent's witness testified that this data indicates that Respondent's stockholders have borne in the past and will continue to bear in the future a substantial burden of supporting Respondent's construction program.

Respondent further stated that both it and its customers have realized substantial benefits from this Commission's previous actions in including a portion of electric CWIP in rate base, in terms of reduction of the amount of permanent financings required in a period of high capital costs, maintenance of Respondent's financial integrity and ability to raise capital, and reduction in the revenue requirements associated with Clinton Unit No. 1 over the service life of the plant.

Respondent's witness also testified that inclusion of CWIP in rate base has enabled Respondent to avoid mortgage coverage problems over the three year period 1980-1982 during which Respondent has financed over $1,000,000,000 of construction expenditures. The witness sponsored an exhibit which displayed Respondent's coverage ratio and amount of first mortgage bonds issuable under the terms of its mortgage for each quarter of 1980-1982 as compared to those which would have been experienced had CWIP not been included in Respondent's rate base. This exhibit indicated that had CWIP not been included in its rate base, Respondent would effectively have been precluded from selling any material amount of first mortgage bonds after the first quarter of 1981. Respondent's witnesses concluded that the maintenance of financial integrity and ability to raise capital on reasonable terms resulting from inclusion of CWIP in its rate base benefits both Respondent and its ratepayers.

Respondent presented evidence to show the reduction in final cost of, and revenue requirements associated with, a project where CWIP is included in rate base and capitalization of AFUDC on the corresponding investment is ceased. The cost of Clinton Unit No. 1 is estimated by Respondent to be reduced by approximately $133,000,000 because of the inclusion of $97 million of CWIP in rate base in Docket No. 79-0071 and an additional $278 million of CWIP in Docket No. 80-0544. Further, the revenue requirements over the service life of Clinton Unit No. 1 are estimated by Respondent to be reduced by approximately $767,000,000 due to this Commission's previous actions in including CWIP in rate base. Inclusion of CWIP in rate base in Docket Nos. 79-0071 and 80-0544, and the associated cessation of capitalization of AFUDC, has reduced the revenue requirement (return, depreciation and taxes) for the first year of operation of Clinton Unit No. 1 by an estimated $48.7 million.

Respondent presented evidence to show the relationship between the amount of CWIP included in rate base in this case and the additional revenue requirements to service the investment in Clinton Unit No. 1 when it is placed in service. Respondent's presentation showed that if no CWIP were included in rate base in this case, an increase in electric operating revenues of $505,352,000 would be required to service the investment in Clinton Unit No. 1 when it is placed in service. If $375 million of construction work in progress were included in rate base, an increase in electric operating revenues of $405,184,000 would be required to service the investment in Clinton Unit No. 1 when it is placed in service.

If $875 million of CWIP were included in rate base in this case, an increase in electric operating revenues of $274,683,000 would be required to service the investment in Clinton Unit No. 1 when it is placed in service. Respondent contends that inclusion of

additional amounts of CWIP in rate base will further reduce the additional revenue requirement necessary to service the investment in Clinton Unit No. 1 when it is placed in service and will thereby spread out over a longer period of time the increase in operating revenues needed to support the plant when it goes into operation.

Respondent's witness identified other benefits arising from inclusion of CWIP in rate base in addition to benefits such as maintenance of the firm's financial integrity, maintenance of lower capital costs which affect both current and future rates, and reduction of the final cost of a project and the revenue requirements associated with it. The witness testified that ratepayers benefit from the inclusion of CWIP in rate base because they receive assurances that electric energy supplies will continue to be adequate, which assurances enhance the value of assets owned by the ratepayer, such as a home or business. While most present customers will receive service from the new plant and will benefit from the lower revenue requirements when it goes into service, even current customers who never receive service from the plant may be benefitted if the value of their property is increased by the prospect of continued efficient service.

In addition, this witness testified that difficulties in financing expansion resulting from the AFUDC approach may cause a utility to install less capital-intensive, higher fuel cost plant, even if it is not the alternative with the lowest overall revenue requirements. He stated that if a utility has insufficient cash flow to support current construction, it may defer completion of its current construction program without regard to the economic consequences of deferral. Inclusion of CWIP in rate base reduces the probability of delays (and hence, higher costs) in construction activities for financial reasons.

A witness for Respondent presented an exhibit which showed that total revenue requirements over the life of the plant will be less if CWIP is included in rate base than if CWIP is excluded, and that, on a present value basis, the revenue requirement streams under the two alternatives are equal. The analysis was presented using the firm's marginal capital cost data and showed that total revenue requirements are lower by $745,500,000 over the life of the plant if $875 million of CWIP is included in rate base for two years in the construction period.

The Company witness stated that the difference in revenue requirements is due primarily to the fact that if all AFUDC is capitalized, the final installed cost of the project is greater, requiring greater depreciation allowances and return requirements over the service life of the plant. The witness testified that other factors not explicitly included in his analysis would tend to make the alternative of excluding all CWIP from rate base even more expensive. These additional factors include the incidence of gross revenue taxes and the Illinois invested capital tax, and higher costs of capital if all AFUDC is capitalized.

Respondent presented evidence to show that while CWIP has been included in its electric rate base for the past several years, Respondent has maintained electric rates which are among the lowest available to ratepayers in Illinois, and that this position would not be altered with the requested rate increase. Respondent's witness testified that the proposed rate increase including the proposed amount of CWIP is appropriate because it would help to restore Respondent's financial condition to reasonable levels yet would leave Respondent with rates comparable to and in most cases less than those charged by other Illinois utilities.

Two witnesses appearing on behalf of Intervenors offered testimony on the subject of CWIP. One witness, appearing on behalf of the U.S. Department of Defense ("DOD"), reviewed Respondent's financial ratios which would result from granting no rate increase, 50% of the requested rate increase, and 100% of the requested rate increase. He stated that failure to allow any rate increase or additional CWIP would lead to some financial deterioration at a time when Respondent must raise large amounts of capital to finance construction. He expressed his opinion that allowing no more than 50% of the proposed additional CWIP would be sufficient to maintain Respondent's financial condition, particularly its interest coverage ratio, at levels equal to or greater than those achieved in recent years during which, according to the witness, Respondent has attracted capital on favorable terms and maintained favorable financing ratings. The witness presented no specific analysis of the reasonableness of the costs at which Respondent is currently raising capital, such as the sale of long-term debt in 1982 at costs of 14.63% and 14.982%, and made no comment on the downward trend of Respondent's financial indicators in recent years nor on the implications of the recent downgrading of Respondent's first mortgage bonds and preferred stock.

Although agreeing with Respondent's witness that total revenue requirements over the life of a project are reduced if CWIP is included in rate base, the DOD witness contested the conclusions of Respondent's witness concerning the present values of the two alternatives. The witness disagreed with the use of the utility's marginal cost of capital as the proper discount rate for present value analysis on the ground that it was too low. The DOD witness presented an analysis similar to that presented by Respondent's witness using different parameters. The witness also stated that rate base treatment of CWIP is a departure from cost of service pricing and suggested that excluding all CWIP from rate base increases incentives for timely and cost-effective construction activities.

A utility engineer appearing on behalf of the Village of Buffalo testified against the inclusion of CWIP in rate base. The witness did not base his position on any analysis of the financial condition of Respondent but rather on objections to CWIP in principle. The witness summarized his objections to CWIP as follows: it includes in rate base property which is not "used and useful;" it violates the regulatory principle that rates should correspond to the cost of service; it blurs the roles of investors and consumers and causes ratepayers to assume the function of investors; it impacts management incentives for planning and cost control and complicates regulatory oversight; and it results in economic cost, on a present value basis, to ratepayers which is greater than that resulting from capitalization of AFUDC.

In support of the latter point the Village of Buffalo witness offered a comparison of revenue requirements associated with inclusion of CWIP versus capitalization of AFUDC. His analysis indicated that the revenue requirements associated with capitalization of AFUDC were greater in total but lower on a present value basis than the revenue requirements associated with inclusion of CWIP in rate base depending on the time period analyzed and the discount rate used. The witness based his present value analysis on Respondent's embedded cost of capital and used discount rates higher than Respondent's cost of capital which he contended were more representative of ratepayer opportunity costs.

The Commission notes that it has discretion to determine an increment of CWIP to be "used and useful" within the meaning of Section 36 of the Illinois Public Utilities Act which may be included as a component of Respondent's rate base. (See: Citizens for a Better Environment v. Illinois Commerce Commission, supra.)

The Village of Buffalo witness testified that if the Commission determined that Respondent's financial integrity would be threatened by capitalization of all AFUDC, resort should be had to use of surcharges in the form of contributions in aid of construction or customer advances for construction rather than to inclusion of CWIP in rate base. He made reference to three regulatory commission decisions from other jurisdictions, two involving small gas utilities and one involving a small water utility, to support his proposal. The witness presented no specific plan for implementing this proposal.

The Village of Buffalo witness testified on the risks associated with a nuclear construction program which he described as having a higher dollar-per-kilowatt construction cost than other technologies, resulting in higher financing costs; having longer lead times to construction, resulting in greater exposure to cost increases due to inflation; and being subject to increasing real costs due to the maturing nature of the technology. He stated that the one factor above all others driving the trend of increasing real costs for nuclear construction has been the proliferation of regulatory standards which affect power plant design thereby resulting in delays, increased requirements for material and labor and reduced labor productivity. He noted that Respondent had attempted to lessen its risk associated with construction of the Clinton facility by selling a portion of its interest in the plant to other utility systems.

On rebuttal, an economist testifying on behalf of Respondent opposed the present value analyses of Intervenor witnesses. Respondent's witness stated that the use of a different rate for discounting than the rate used to determine the initial value of the streams of revenue requirements (i.e., the utility's marginal cost of capital) is lacking any empirical or theoretical support. The witness testified that the appropriate discount rate for use in the present value comparison under consideration is the firm's marginal cost of capital which is both the opportunity cost of the capital employed and the social opportunity cost of funds, that is, the weighted average of all individual opportunity costs.

The Illinois Power witness also stated that the analyses of the Intervenor witnesses failed to take into account a number of factors which if considered would raise the revenue requirements associated with capitalization of AFUDC relative to the revenue requirements associated with inclusion of CWIP in rate base, including the fact that if CWIP is not included in rate base, the utility must undertake additional outside financing during the construction period, thereby (1) raising embedded costs which are applicable to the entire rate base during the construction and in-service periods; (2) supporting increases in the AFUDC rate and hence in the total amount of capitalized AFUDC; and (3) increasing the utility's expense for the invested capital tax which is based on total capitalization. Other factors not taken into account or not fully taken into account were revenue taxes, the invested capital tax and the impact of higher capital costs if CWIP is excluded from rate base.

Respondent's witness, a certified public accountant, presented rebuttal evidence concerning the proposal to utilize contributions in aid of construction or customer advances for construction in lieu of CWIP. The witness noted that this proposal would not alleviate downward pressure on Respondent's coverage ratios since the funds

accumulated under this proposal would not be includable in net earnings or revenues for the purpose of calculating interest coverage ratios. He questioned whether the total revenue requirements associated with the alternative proposals would not in fact be greater than those associated with inclusion of CWIP in rate base. The witness also challenged the opinion of the Intervenor witness that funds received under the alternative proposals would not be includable in gross income for federal tax purposes, noting that the proposals were a severe departure from the traditional application of contributions in aid of construction and customer advances for construction and that the Internal Revenue Service has challenged the claimed non-taxable status of a similar surcharge plan used by another utility.

Respondent's witness also challenged the contention that inclusion of CWIP in rate base defeats incentives for control of construction costs. He identified ongoing financial and operating incentives which Respondent has for timely and cost-effective construction. Financial incentives identified by the witness include the avoidance of additional outside financings which, if they are required, increase interest and preferred dividend requirements, raise embedded capital costs and if common equity must be sold, dilute earnings and may negatively affect the price of common stock. If common stock is sold at prices below book value, stockholders' capital is confiscated.

The Company witness also stated that reductions in the ratio of internal cash generation to total construction expenditures increase the risk to Respondent's stockholders that future dividend growth will be lower and raise the likelihood that senior securities will be downgraded. Operational incentives include the need to keep construction costs low in order to keep rates low thereby supporting increased sales which provide an expanded base for fixed cost recovery, and enhancing Respondent's ability to compete with alternate energy sources or with other utility service territories in which industrial customers may locate plants or to which they might shift production. The witness testified that including a portion of CWIP in rate base does not remove the financial and operating pressures which provide these incentives. He stated that even if the full amount of CWIP proposed by Respondent were included in rate base, Respondent's security holders would still be required to support 43-52% of Respondent's investment in Clinton Unit No. 1 in 1983.

Normal and Galesburg contend, with respect to CWIP in Illinois Power's rate base, which was joined in by the Urbana School District, that ratepayers be given the opportunity to participate in equity holdings at a discount and in a manner which would lower their utility costs by dividends effectively offsetting rates. Specifically they urge Respondent to offer shares of its stock to its ratepayers at a discounted rate when CWIP, in the magnitude of that involved in this case, is sought to be included in rate base so as to provide their ratepayers with an equitable and fair means to participate when the Company seeks to acquire additional capital. These Intervenors argue that the Commission should relieve ratepayers from the responsibility of providing investment capital without the benefits of investors, and left with the total burden of cost and risks for the investments of others.

Respondent claims that the inclusion of CWIP in rate base does not result in ratepayers providing investment capital but only supporting the investment through a cash return requirement. All the investment in CWIP which Illinois Power seeks to have included in rate base has already been provided by investors through the capital markets. It is Respondent's position that the inclusion of CWIP in rate base only results in the provision of a return on that investment during the construction period.

The Commission is of the opinion that Illinois Power should study making available to its ratepayers a stock purchase option or similar plan of financing wherein the ratepayers become participating members by investment in CWIP in rate base, and in return possibly receive dividends and lower rates. The results of this study should be reported to the Commission.

The Commission notes that it has under investigation in Docket No. 80-0167 the question of proper incentives for effective cost control performance at the Clinton project.

An officer of Respondent, with responsibilities for the Clinton construction project, presented testimony and exhibits concerning the cost and schedule status of the project. The witnesses' evidence principally addressed increases in the estimated cost of the project which have occurred since the conclusion of Respondent's last rate proceeding. A revised cost estimate was prepared in December 1981 and April 1982; the latter estimate was associated with a one-year extension of the scheduled in-service date.

Respondent's witness presented an exhibit which broke out the cost increases in the December 1981 estimate over the previous estimate (issued in December 1980) as between direct construction costs of Respondent's contractor, direct construction costs of Respondent, owner's expenses, architect/engineering costs, and AFUDC, and further discussed these increases through a total of 27 line items, including a decrease in AFUDC attributable to inclusion of additional CWIP in rate base commencing in July, 1981.

A second exhibit sponsored by the Illinois Power witness set forth a similar analysis of cost increases between the December 1981 and April 1982, cost estimates including identification and discussion of 25 line items. This exhibit specifically identified $246.6 million of the total $350.9 million cost increase in the April, 1982 cost estimate as resulting from the one-year schedule extension, including $115.5 million of additional AFUDC.

Additional information on the cost increases in the two estimates, provided in discovery, were placed into evidence during cross-examination. These exhibits explained the cost estimating system used by Respondent, provided further detail on the major factors resulting in cost increases, and provided information on some 32 line items of cost for the December 1981 cost estimate and some 46 line items of cost for the April 1982 estimate and on a number of other factors not specifically quantifiable into particular cost increases.

The Illinois Power witness identified the principal factors contributing to the cost increases and schedule extension reflected in these estimates such as the impact of changes in regulatory requirements and interpretations of regulations, additional equipment and testing required as a result of the Three Mile Island accident, increased expenditures for quality control/quality assurance activities, the impact of a January, 1982 stop work order on safety-related electrical cable tray installation arising out of a difference of opinion between Respondent and the Nuclear Regulatory Commission regarding the proper timing of inspections of completed work, which resulted in several changes in installation and inspection procedures, the need to redesign the plant's control rod drive system in light of new load requirements, and an increase in the AFUDC rate reflecting higher money costs.

In its Order in Docket No. 80-0544, the Commission after a detailed review of the evidence including evidence presented by Respondent similar to that described above, noted that although cost

increases for the Clinton project have been substantial, the cost estimates and estimated final cost are comparable to the industry experience; and concluded that Respondent has been subject to the same factors which have affected the entire electric utility industry. Illinois Power's evidence in this case indicates that such factors have continued to impact Respondent resulting in further cost increases. The Commission, however, intends to continue to monitor closely the cost and schedule status of the Clinton project through the monthly reports and periodic cost estimates which it requires Respondent to file.

A member of the Commission's Accounts and Finance Department also addressed in testimony the topic of CWIP in the context of a firm with a large construction budget. The witness identified several problems associated with capitalization of AFUDC in the context of a large construction program. He testified that the capitalization of AFUDC fails to provide sufficient cash earnings to meet the financing needs of utilities with major, long-term construction budgets; that cash flow problems, declining interest coverage ratios, and earnings from operations which are insufficient to pay the dividend, result in higher added risk that is directly translated into a demand for a higher rate of return, and that investors discount AFUDC earnings; that when carrying costs on CWIP are met by issuing more securities, investors are asked to provide not only capital but also the dollars required to service that capital, a practice which has been universally condemned in other contexts; that a utility with cash flow problems may be under heavy pressure to delay a construction schedule, which will escalate the cost of the plant and increase operating costs by delaying replacement of less efficient older units by more efficient new units; and that the price signal provided if no CWIP is included in rate base is unrealistically low, and a precipitous rate increase may be required when the plant comes in service in order to service the related investment, which may come as a shock to the ratepayer.

This Staff witness stated that by comparison, the inclusion of CWIP in rate base increases internally generated funds, improves interest coverage ratios and improves quality of earnings, thereby reducing the level of risk perceived by investors. These benefits accrue at a time when the utility's need for capital is the greatest. Further, the rate base treatment of CWIP provides the ratepayer with a quid pro quo in the form of lower revenue requirements associated with the plant than if AFUDC is capitalized.

The Staff witness testified that the inclusion of CWIP in rate base should be no more than necessary to assure adequate cash flow to cover all operating expenses, the interest charges on debt, the dividend obligation on preferred stock and a reasonable level of dividends on common stock.

The witness rejected certain philosophical arguments advanced in opposition to rate base treatement of CWIP. He stated that the objection that the inclusion of CWIP converts ratepayers into investors is misplaced, since the historical position of the investor supplying the capital is not disrupted; the ratepayer services the investment carrying costs but does not provide the capital. The witness testified that the argument that inclusion of CWIP will stimulate unnecessary plant construction is without foundation, since the addition of capacity at much higher than previous embedded costs will put the utility under earnings pressure that means lower earnings, not higher profits.

Finally, the Staff witness characterized the inter-generational equity challenge as often mistaken. Under pricing structures based

on embedded costs, rates will never exceed marginal costs during periods of cost escalation, and the future subsidization contention is not realized. Consumption patterns of present customers create much of the need for capacity expansions and for replacement of existing facilities. Refundings of maturing debt at current costs in excess of the cost of debt retired create a measure of the cash flow problems and are directly related to existing capacity and current generation ratepayers.

The Staff witness addressed the problem of the sizeable rate increase required when a large new capital-intensive baseload plant is placed in service. He proposed consideration of a plan for moderating the initial rate increase associated with placing the plant in service by setting rates at the net income level and allowing the restoration of carrying charges to rate base through a capitalization procedure. This procedure would be followed until the book cost of the plant were equal to the cost which would have resulted if no CWIP had been included in rate base. The witness presented exhibits depicting 1982-1987 values for certain financial statistics under various assumptions of the amount of CWIP in rate base as well as under the witness' plan. These projections were prepared using the Commission's Regulatory Analysis Model.

Respondent contends that the Staff witness' proposed plan or any similar plan for alternative ratemaking treatment of the Clinton plant when it is placed in service would be a significant action with serious ratemaking and financial implications. The Staff witness' proposal did not receive sufficient study and was not sufficiently evaluated on the record in this proceeding to provide a basis for an informed decision.

The Commission, in reviewing the Staff witness' proposed plan, is of the opinion that it addresses some of the serious objections raised by various parties in this and other rate cases. It provides some solutions to such issues as cash flow and financing needs which occur during extended periods of construction and plant additions, avoidance of extraordinary changes in rate base and rates, correct pricing signals and a more reasonable representation and procedure for accounting for plant costs. The Commission is also of the opinion that Respondent should research the applicability of the plan in future cases and resolve the problems which such a proposal may present; this study should be conducted in conjunction with the Commission Staff with the expectation of producing a positive and workable proposal. This study should be completed and a report filed with the Commission's Chief Clerk's Office not later than 12 months from the date of this Order; copies of the report should also be served on the Manager of the Commission's Public Utilities Division, with copies made available to all parties on request.

The Commission has thoroughly reviewed and analyzed all the evidence presented by witnesses for Respondent, Intervenors and Staff in this case relevant to the issue of whether and to what extent construction work in progress should be included in Respondent's rate base. The Commission has reviewed the historical and forecasted financial statistics presented by Respondent and Staff, including projections of financial statistics if varying amounts of CWIP are included in rate base; the comparisons made by witnesses for Respondent and Staff between Respondent's historical and forecasted financial performance and that of other utilities having high quality credit ratings; information in the record on the factors considered by security rating agencies and the factors which influence investor attitudes towards Respondent's securities; data on the size of Respondent's construction program in relation to its total capitalization and net plant; evidence concerning the cost and schedule of Respondent's construction program; information on

the impact which rate base treatment of CWIP has previously had on maintaining Respondent's ability to raise capital; data on the reductions in installed cost of and total revenue requirements associated with Clinton Unit No. 1 resulting from inclusion of CWIP in rate base; evidence on the comparative revenue requirements resulting from inclusion or exclusion of CWIP in rate base; testimony on other asserted benefits or burdens to the ratepayer and stockholder of inclusion or exclusion of CWIP in rate base; data on Respondent's construction and financing needs, the current and foreseeable state of the capital markets and Respondent's present ability to raise capital; evidence on Respondent's financial condition and the impact of its large balance of CWIP on its ability to maintain financial integrity and to raise capital including the recent downgrading of its senior securities; evidence of Respondent's current and proposed rate levels as compared to those in effect for other Illinois utilities; and evidence on the size of the operating revenue increase which will be required to service the investment in Clinton Unit No. 1 when it is placed in service, and the lessening of this increase which may be occasioned if additional CWIP is included in rate base at this time.

Based on all this evidence, the Commission is of the opinion and finds that the size of Respondent's investment in construction work in progress on which it is presently earning no cash return is so great that it is impairing and will continue to impair Respondent's ability to raise capital to continue its construction program unless Respondent is allowed to earn a cash return on a larger portion of that investment.

The Commission notes among others the following factors of record in support of its conclusion: (1) Respondent's investment in construction work in progress is sizeable, exceeding 60% of Respondent's total capitalization and approximating its net plant in service; taking into account the CWIP presently included in rate base, some 38% of Respondent's total capitalization presently earns no cash return. (2) Respondent faces considerable additional financing requirements during the next two years in order to complete its construction program. (3) Respondent's financial condition as measured by financial ratios indicating interest coverage, internal cash generation and cash flow and quality of earnings have deteriorated over the past several years; Respondent's senior securities have recently been downgraded and are in jeopardy of further downgrading; downgradings raise the cost of capital to Respondent and reduce the availability of capital in the external markets. (4) Respondent's low level of internal cash generation is limiting its ability to finance construction from internal sources and increasing its dependence on the external capital markets. (5) Respondent's high percentage of AFUDC earnings to total earnings is reducing the quality of its earnings which is a circumstance viewed negatively by investors that affects the cost of capital. (6) Respondent has been required, in order to support its construction program, to sell a substantial amount of new common stock at prices below book value during the last three years; this impairs Respondent's ability to raise capital through the sale of common stock. (7) Continued difficulty in raising capital could threaten Respondent's ability to raise capital needed to complete construction of Clinton Unit No. 1 and therefore result in delay in the completion of the unit which would increase its ultimate total cost.

The amount of CWIP which should be included in rate base in order to maintain Respondent's financial integrity and ability to raise capital while maintaining reasonable current rate levels is not susceptible of being exactly determined through a precise mathematical formula. Application of judgment by the Commission based on full consideration of all the factors heretofore cited including the effect of inclusion of an amount of CWIP on rate-

payers as measured by the resulting rate levels is necessary to this determination.

Based on consideration of all the evidence, the Commission is of the opinion and finds that $625 million of CWIP should be included in Respondent's rate base. In making this determination the Commission relies particularly on the deterioration of Respondent's financial condition and on the evidence presented by Respondent and Staff which shows that Respondent's financial statistics relating to internal cash generation and cash flow, which are the principal measurements of the effect of its large construction program on the ability to raise capital and which are specifically affected by rate base treatment of CWIP, will not be improved to necessary levels if any substantially lower amount of CWIP is included in rate base.

The Commission also relies, with respect to the effect of this determination on the ratepayer, on the evidence which shows that total revenue requirements over the life of Clinton Unit No. 1 will be lower by some $49,575,000 if this amount of CWIP is included in rate base than if it is excluded and that the present value of revenue requirements for inclusion of CWIP in rate base are equal to or less than the present value of revenue requirements associated with capitalization of AFUDC; on the fact that inclusion of additional CWIP in rate base will reduce the amount of additional securities required to be sold to support construction, which if sold would be issued at cost rates higher than current embedded costs thereby increasing both present and future rates; on the fact that inclusion of CWIP in rate base heretofore has reduced the total cost and total revenue requirements for Clinton Unit No. 1 and that inclusion of additional amounts would have similar impact; on the fact that ratepayers as well as the utility would be harmed if Respondent's financial condition were to deteriorate further, resulting in higher current costs of capital or possible added delays in the completion of its construction program; on the fact that inclusion of additional CWIP in rate base at this time will lessen the size of the revenue increase Respondent will require when Clinton Unit No. 1 is placed in service; and on the fact that, even with this amount of CWIP included in rate base, Respondent's rates, particularly its residential rates, will continue to be among the lowest available to ratepayers in this State.

RATE OF RETURN

The use of an average forecasted capital structure for the test year is preferred by the Commission. The use of an end of year forecasted capital structure would have consumers paying rates higher than actual costs would dictate as necessary throughout the forecasted test rate. The use of the average forecasted capital structure will have consumers paying rates which would overcompensate Respondent for the first six months of the forecasted test year and undercompensate Respondent for the last six months of the test year. In this manner, Respondent should only be reimbursed for total costs.

Respondent's evidence shows that its proposed tariffs would produce a 12.64% rate of return on the combined electric and gas rate bases for the 1983 test year. The capital structure and embedded costs shown on IP Exhibit 9.34 Revised are as follows:

Electric Utility

Class of Security	Capitalization Ratio	Cost	Weighted Cost
Long Term Debt	47.52%	9.61%	4.57%
Preferred Stock	9.66	7.97	0.77
Common Stock Equity	42.82	16.58	7.10
Cost of Capital			12.44%

Gas Utility

Class of Security	Capitalization Ratio	Cost	Weighted Cost
Long Term Debt	47.52%	9.61%	4.57%
Preferred Stock	9.66	7.97	0.77
Common Stock Equity	42.82	20.08	8.60
Cost of Capital			13.94%

Combined Basis

Class of Security	Capitalization Ratio	Cost	Weighted Cost
Long Term Debt	47.52%	9.61%	4.57%
Preferred Stock	9.66	7.97	0.77
Common Stock Equity	42.82	17.05	7.30
Cost of Capital			12.64%

The rates of return on fair value rate base produced by Respondent's proposed rates are 10.54% for the electric utility and 10.15% for the gas utility for the 1983 test year.

Respondent's proposed embedded cost rates and capital structure are based on the weighted average capital structure (average of thirteen monthly balances) forecasted for the 1983 test year. The forecast was based on the issuance of $200 million of long-term debt at a cost rate of 14 percent in 1982 and $100 million of long-term debt at a cost rate of 12 percent in 1983.

Respondent's actual capital structure at December 31, 1981, and the projected capital structure at December 31, 1982, were shown by the evidence and appears on IP Exhibit 9.18 to be as follows:

	December 31, 1981	December 31, 1982
Long Term Debt	47.33%	48.12%
Preferred Stock	11.92	10.27
Common Stock Equity	40.75	41.61
	100.00%	100.00%

Respondent's capital structure witness, testified that Respondent has been raising its equity component in light of the increasing business risk it has experienced in the past several years. He testified that Respondent has capitalization goals of 45 percent or less long-term debt, 12 percent or less preferred stock, and 43 percent or more common stock equity. The witness stated that increasing the equity component relieves some of the pressure on Respondent's coverage ratios and permits Respondent to sell a lesser amount of new senior securities at current high cost rates.

A financial consultant appearing on behalf of the Department of Defense recommended that a capital structure with a slightly lower equity ratio and slightly higher debt component than that proposed by Respondent be employed for test year purposes. The

witness indicated that the higher debt component could be achieved by the sale of new debt rather than new equity in 1983 as forecasted by Respondent. The new debt would have a higher cost than originally forecasted by Respondent.

A member of the Commission's Economics and Rates Department, who holds a doctorate in finance, presented data to evaluate the Company's proposed capital structure. The witness presented the actual capital structures at December 31, 1981 and the forecasted capital structures for 1984-1986 for nine electric utilities which he found to be comparable to Respondent. The data showed that Respondent's forecasted capital structure was not dissimilar to the forecasted capital structures of the comparable utilities. On the basis of this analysis, the witness did not recommend any change in Respondent's proposed capital structure.

Respondent offered the testimony of a Professor of Finance and Managerial Economics, from the University of Wisconsin, as to the general economic trends (and their impact on Respondent) and the investor required return on equity of Respondent. This witness reviewed general economic trends and conditions relevant to the determination of the cost of common equity for Respondent, including statistics on gross national product, industrial production, inflation and interest rates. Based on his analysis of economic trends and conditions, Respondent's witness concluded that high inflation rates, high interest rates, rising capital, construction and operating costs, declines in sales growth, and increasing environmental and other regulatory restrictions have increased the risk of electric utilities.

Respondent's witness performed a risk premium analysis and a discounted cash flow ("DCF") analysis in connection with estimating the investor-required return on equity for Respondent. As a set of alternative investment opportunities for use in his risk premium analysis, the witness utilized the S&P 400 Industrial Index. He supported the risk-comparability of an investment in common stock of Respondent and an investment in the common stock of the average S&P 400 Industrials firm by reference to the factors which have negatively affected Respondent and other public utilities in recent years and have increased the risk of utilities relative to that of industrial firms.

To determine the risk premium for the average S&P industrial firm, the witness referred to two studies, one of which examined actual rates of return on common stocks and on long-term U.S. Treasury securities for various historical periods, and the second of which used the DCF method to estimate investor-required returns on groups of industrial common stocks at various points in time from 1964 to 1979, and determined risk premiums by comparing these investor-required returns to corresponding yields to maturity on long-term U.S. Treasury securities. According to the witness, these studies indicated a risk premium for industrial common stock relative to long-term U.S. Treasury securities in the range of 5.0% to 7.0%. Using an average yield on U.S. Treasury securities of 14.3% and a risk premium of 5%, the witness estimated the investor-required return on common equity to be 19.3%.

For his DCF analysis, Respondent's witness used Respondent's current indicated dividend and a representative market price and employed a method of calculation which takes into account Respondent's quarterly payment of dividends. He estimated a near-term (5 year) investor-expected growth rate for Respondent of 3.5% per year by reference to published forecasts which indicated projected near-term growth rates, on average, of 3.6-4.2%; and an earnings retention analysis which suggested a near-term growth rate of 3.1-3.8%. He estimated a longer term (beyond 5 years) investor-expected growth rate of 5.0% to 5.5%. Using the above data, the witnesses' DCF estimate of the investor-required return on equity for Respondent was 17.7-18.0%.

Taking into account his risk premium and DCF analyses, Respondent's witness concluded that the investor-required return on Respondent's common equity is at least 19%. He adjusted his investor-required return estimate to reflect the higher cost of equity raised through the sale of new shares of common stock due to flotation costs and expenses, to underwriting costs, and to market pressure on stock price which he associated with new stock offerings. With this adjustment, the witness estimated the cost of equity capital to be 19.5%. He used Respondent's proposed test year capital structure and projected embedded cost rates to determine an overall cost of capital for the 1983 test year of 13.70 percent on original cost rate base.

The Department of Defense ("DOD") offered the testimony of two witnesses, both financial consultants, on issues relating to the cost of capital. The first witness addressed the relative riskiness of Respondent's common stock compared to that of industrial firms. He offered various measurements as to the relative riskiness of investments in common stock. On the basis of the results of his examination of risk, the witness indicated that an investment in Respondent's common stock is not as risky as an investment in industrial common stock. The witness opposed the analyses of relative riskiness employed by Respondent's witness, and offered specific objections to the risk premium and DCF analyses performed by Respondent's witness. This witness also addressed the question of the proper adjustment to cost of equity estimates to reflect issuance costs. He recommended an adjustment for this purpose of 0% to 0.3% depending on the number and size of new common stock issues.

The second witness appearing on behalf of the DOD estimated the cost of equity capital for Respondent using the DCF method. The witness performed a DCF analysis using data for 94 electric utilities. He determined dividend yields for the 94 utilities using data on current indicated dividends and data on the market price of common stock. To estimate investor-expected dividend growth rates, the Department of Defense witness referred to historical data on growth in dividends, earnings and book value per share. He identified growth rates in earnings, dividends and book value for the 94 utilities as a group over recent periods ranging from 0.9% to 5.7% per year.

The DOD witness based his dividend growth rate estimates principally on historical growth rates in book value per share rather than on the higher historical growth rates for dividends and earnings. He also examined an earnings retention analysis for this purpose; however, the witness noted that investor growth expections may be affected by the prospect of dilution due to sale of new common stock below book value. In addition, the witness performed a separate DCF analysis for Respondent alone, using dividend yield, market price, and growth data for Respondent.

The DOD witness concluded that the total cost of attracting new common equity capital for Respondent, based on his analysis of 94 utilities and including the allowance for issuance costs recommended by his associate, was in the range of 14.3-15.4%; and that the total cost of attracting common equity capital for Respondent based on his DCF analysis of Respondent alone was 14.3-15.7%. He recommended a return on equity for cost of service purposes of 14.9% and an overall rate of return of 11.76%.

A Professor of Finance from Washington University, appearing on behalf of the Industrial Intervenors, used two methods in determining a cost of equity capital to Illinois Power. He applied a risk adjusted money cost method which involves adding a pure interest rate, a financial risk premium and an inflation premium. Using this approach, the witness developed a cost rate of common equity of 13.09% to 14.09% by adding an historical real rate of interest

of 2.21%, a financial risk premium of 3.88% and an inflation premium of 7-8%. After the adjustments for issuance costs and market pressure, this method produced a required rate of return of 13.78% to 14.83%.

The witness also applied a DCF approach in which he added a dividend yield and the anticipated future growth rate in dividends per share to produce a cost of common equity capital. The witness analyzed these elements with respect to Illinois Power and twelve comparable utility companies. To compute the dividend yield, the witness used a 29-month period ended May 31, 1982 and an average of dividends per share for the years 1980, 1981 and the indicated dividend for 1982. The computed yields were then adjusted upward by 5% to allow for issue expenses and market price pressure resulting from the issuance of additional shares. This resulted in an adjusted yield of 13.19% for Illinois Power and 12.31% for the comparable firms.

In order to determine the growth rate to be used in connection with the DCF method, the Industrial Intervenors witness computed the growth in book value per share both for Illinois Power and the twelve comparable companies. The growth rates were computed for a ten-year period, 1971-1981. This resulted in a ten-year growth rate in book value per share of Illinois Power's common stock of 1.78% and an average growth rate for the comparable companies of 3.29%. Combining the weighted average dividend yield and the growth rate in book value per share for Illinois Power and the twelve comparable companies resulted in an indicated cost of common equity capital of 14.97% for Illinois Power and 15.60% for the comparable companies.

On the basis of his risk premium and DCF analyses, the Industrial Intervenors witness concluded that the cost of equity capital to Illinois Power was 14.90%. His decision to select 14.90% as the cost of common equity capital was influenced by the facts that (1) the general levels of inflation and interest rates, hence cost of equity capital, have declined and are continuing to decline, and (2) the tremendous improvement in the financial position of Illinois Power which has reduced the risk of its common stockholders.

An economist appearing on behalf of the People also presented evidence on the cost of capital to Respondent. This witness presented a DCF analysis of the cost of capital for Respondent alone using dividend and market price data for Respondent to determine dividend yield and historical data on Respondent's earnings retention rate, earned return on equity, growth in dividends, earnings and book value per share to estimate investor-expected future growth in Respondent's dividends. This analysis produced an estimated cost of equity capital of 14.4% to 15.4%.

The witness also developed a sample of 24 utilities which he believed comparable to Respondent based on a series of risk measures. The witness then prepared cost of equity estimates for the sample group of utilities using each of six growth rate techniques. The six growth rate measures indicated a range of cost of equity estimates for the 24 utilities of 9.21-19.13%. The range of the cost of equity estimates for the 24 utilities as a group for the six growth rate techniques was 14.46-15.26%. Based on both of his analyses, the witness indicated a bare bones cost of equity for Respondent in the range of 14.4-15.3%, with a midpoint of 14.85%.

The economist for the People also addressed the issue of an appropriate adjustment for issuance costs, and concluded that the appropriate additive adjustments for flotation costs is 40 basis points based upon the Company's yearly sales of new stock in previous years. With this adjustment, the witness recommended a return on

equity of 14.8% to 15.7% with a midpoint of 15.25%. He associated his recommended return on equity with allowance of 67% of the requested additional construction work in progress in rate base (i.e., a total of $710 million). He testified that if an additional amount of construction work in progress significantly greater than 67% of the proposed additional amount were allowed, the required return on equity would be lowered, and that if an additional amount of CWIP included in rate base were significantly lower than 67% of the proposed additional amount, the required return on equity would be raised.

The People's witness made no finding or recommendation concerning capital structure, embedded cost rates or overall rates of return.

The Staff witness who presented testimony on Respondent's capital structure also offered evidence on the cost of capital to Respondent. The witness used a DCF model which considers the quarterly payment of dividends to determine the cost of equity capital. He determined the dividend yield using Respondent's current indicated annual dividend per share and current market price data.

To determine the investor-expected dividend growth rate, the witness examined historical data on growth in book value per share, earnings per share and dividends per share for Respondent over various time periods, and concluded that the historical growth rate is in the range of 2.0% to 3.0%. He also employed the retention rate approach. Based on a review of historical data on retention rates for Respondent and nine comparable firms, he concluded that the minimum retention rate expected by investors is 20%. The Staff witness used 25% as the maximum expected retention rate.

Based on a review of historical earned returns on equity for Respondent and the comparable companies, and giving particular weight to earned rates of return as of July 2, 1982 based on the trailing twelve months, the witness concluded that 14.0% is the minimum earned return expected by investors. He further testified that with Respondent's construction program expected to moderate in the future, an earned return of 16.0% would be the maximum expected earned return on equity. The combination of the range of expected earned rates of return of 14.0%-16.0% and the expected retention rates of 20%-25% indicated a range of expected growth rates of 2.8% to 4.0%, which the Staff witness used for purposes of his analysis. In his judgment, Respondent's historical growth rates in book value, dividends and earnings did not equal the investor expected growth rate in this case.

The Staff witness allowed an adjustment of 14 basis points for flotation expenses. This adjustment allows Respondent to recover the actual dollar cost of public stock issues since the last rate case. To assure the proper repayment, the witness used a two year amortization period with the present value of the yearly payments equal to the actual issuance costs. The witness did not make an adjustment for additional public offerings since rate relief will reduce the probability of new issues during 1983 and 1984.

Based on the data identified above, and including an adjustment for flotation costs, the Staff witness estimated the cost of equity for Respondent to be 16.02% to 17.37% with a mid-point of 16.70%. He proposed on Staff Exhibit ROR 1.14 an overall rate of return between 12.22% and 12.80%, with a midpoint of 12.51%.

The Commission has thoroughly reviewed the evidence presented by Respondent on its financing plans and forecasted interest and preferred dividend rates and capitalization goals and the reasons advanced in support thereof. The Commission is of the opinion that the weighted average capital structure and embedded cost rates for senior capital projected by Respondent for the test year should be utilized to determine the weighted cost of capital and fair rate of return in this proceeding.

The Commission has thoroughly reviewed the methods used by the witnesses to adjust the return on equity to capture flotation expenses. The Commission is of the opinion that amortizing the actual or estimated dollar cost of new equity issues over the period the rates are expected to be in effect such that the present value of the yearly payments equal the actual or estimated issuance costs is the appropriate method of reimbursing utilities for issuance expenses.

Based on consideration of all the evidence presented in this proceeding pertaining to cost of capital for Respondent, including its substantial financing requirements and the impact of the magnitude of its construction program on the risk of investment in its securities, the Commission is of the opinion and finds that Respondent's cost of common equity for the test year is 15.50% and the Respondent's overall cost of capital for the same period is 11.98% as follows:

Class of Security	Capitalization Ratio	Cost	Weighted Cost
Long Term Debt	47.52%	9.61%	4.57%
Preferred Stock	9.66	7.97	0.77
Common Stock Equity	42.82	15.50	6.64
Cost of Capital			11.98%

Having given due consideration to all the evidence presented in this proceeding and current conditions including recent and proposed increases of substantial magnitude in the prices of pipeline gas supplies available to Respondent which may effect the marketability of such gas and the recovery of costs therefor, which recovery is the subject of inquiry by this Commission in Docket No. 82-0559, the Commission is of the opinion and finds that the fair rate of return which Respondent should be allowed on its original cost electric rate base for the 1983 test year is 11.98% and that the fair rate of return which Respondent should be allowed on its original cost gas rate base for the 1983 test year is 11.98%. The corresponding returns on fair value electric and gas rate bases are 9.83% and 8.67%, respectively.

The Commission, having examined the record herein, and being fully advised in the premises, is of the opinion and finds that:

(1) Respondent is an Illinois corporation engaged in the generation, transmission, sale and delivery of electricity and the distribution and sale of natural gas in Illinois and as such is a public utility within the meaning of the Illinois Public Utilities Act;

(2) the Commission has jurisdiction over Respondent and of the subject matter hereof;

(3) on February 19, 1982, Respondent filed with this Commission tariff sheets containing rate schedules by which it proposed a general increase in electric rates and a general increase in natural gas rates for all classifications of service, effective March 22, 1982; said tariff filing was accompanied by an appropriate supplemental statement in accordance with the rules of the Commission;

(4) due notice of the filing of said filed tariff sheets was given by Respondent pursuant to law and the rules and regulations of the Commission;

(5) on March 10, 1982, the Commission suspended the filed tariff sheets to and including July 19, 1982, and on July 14, 1982, the Commission resuspended said filed tariff sheets to and including January 19, 1983, all in accordance with the provisions of Section 36 of the Illinois Public Utilities Act;

(6) notice of the initial hearing held in this cause was mailed by the Chief Clerk of the Commission to Respondent, the Mayor or Attorney and Clerk of the municipalities within Respondent's electric and gas service areas in Illinois, and to such other persons or entities as are shown by the docket sheets maintained by the Chief Clerk of the Commission, all in accordance with the requirements of the Illinois Public Utilities Act and the rules and regulations of this Commission;

(7) statements of fact and conclusions reached in the prefatory portion of this Order are amply supported by the evidence of record and are hereby adopted as findings of fact;

(8) use of a pro forma test year ending December 31, 1983, with adjustments as described herein, is appropriate for ratemaking purposes in this case;

(9) Respondent's original cost electric rate base for the test year ending December 31, 1983 is $1,536,310,000;

(10) Respondent's fair value electric rate base for the test year ended December 31, 1983, is $1,873,567,000;

(11) Respondent's original cost gas rate base for the test year ending December 31, 1983, is $284,994,000;

(12) Respondent's fair value gas rate base for the test year ending December 31, 1983 is $394,021,000;

(13) rates which are presently in effect for electric service furnished to the customers of Respondent do not produce a fair and reasonable return to Respondent on its investment in electric plant in rate base and recovery of operating costs of electric service furnished to its customers; such existing rates are not in all respects just and reasonable and should be permanently cancelled and annulled when rates allowed to become effective by virtue of this Order become effective;

(14) rates which are presently in effect for gas service furnished to the customers of Respondent do not produce a fair and reasonable return to Respondent on its investment in gas plant in rate base and recovery of operating costs of gas service furnished to its customers; such existing rates are not in all respects just and reasonable and should be permanently cancelled and annulled when rates allowed to become effective by virtue of this Order become effective;

(15) the fair rate of return which Respondent should be allowed on its original cost electric rate base and fair value electric rate base as found herein for the test year ending December 31, 1983, is 11.98% and 9.83%, respectively;

(16) the fair rate of return which Respondent should be allowed on its original cost gas rate base and fair value gas rate base as found herein for the test year ending December 31, 1983, is 11.98% and 8.67%, respectively;

(17) rates proposed by Respondent for its electric operations in Illinois would produce a rate of return in excess of a return that is fair and reasonable; said filed tariff sheets proposing said electric rates should be permanently cancelled and annulled;

(18) rates proposed by Respondent for its gas operations in Illinois would produce a rate of return in excess of a return that is fair and reasonable; said filed tariff sheets proposing said gas rates should be permanently cancelled and annulled;

(19) Respondent should be required to file tariff sheets setting forth rates for electric service that will produce annual electric operating revenues of approximately $804,792,000 and result in annual operating income of approximately $184,050,000 for its electric operations for the twelve months ending December 31, 1983; such annual operating income would provide Respondent with a rate of return of approximately 11.98% on its original cost electric rate base of $1,536,310,000 and 9.83% on its fair value electric rate base of $1,873,567; such amounts of operating income and return are not excessive and are fair, just and reasonable;

(20) Respondent should be required to file tariff sheets setting forth rates that will produce annual gas operating revenues of approximately $541,399,000 and result in annual operating income of approximately $34,142,000 for its gas operations for the twelve months ending December 31, 1983; such annual operating income would provide Respondent with a rate of return of approximately 11.98% on its original cost gas rate base of $284,994,000 and 8.67% on its fair value gas rate base of $394,021,000; such amounts of operating income and return are not excessive and are fair, just and reasonable;

(21) under rates allowed to become effective by virtue of this Order, Respondent should reasonably be able to earn approximately $218,192,000 on its combined utility operations or an overall rate of return of 11.98% on the combined original cost rate base of $1,821,304,000 found herein and of 9.63% on the combined fair value rate base of $2,267,588,000 found herein; such amount of operating income, resultant return and the rates producing same are fair, just and reasonable;

(22) Respondent should be directed to design the rates to be set forth in the tariff sheets to be filed pursuant to Findings (19) and (20) above in accordance with the findings and principles concerning rate design set forth in the prefatory portion of this Order; said authorized revenues should be exclusive of add-on taxes and comply fully with recently enacted House Bill 991;

(23) the gas utility depreciation rates proposed for adoption herein by Respondent are proper and adequate; Respondent should be directed to place such depreciation rates into effect effective January 1, 1983;

(24) Respondent is found to be in compliance with the provisions of ERTA, ACRS Section 168(e)(3) and Section 46(f), and Respondent should continue with the applicable accounting and normalization requirements of this Act;

(25) this Order is intended to comply with the requirements of Section 209(d) of the Economic Recovery Tax Act of 1981 so as to ensure that Respondent will be allowed to utilize ACRS and the tax credits provided in Section 38 of the Code, that the tax benefits associated with the use of ACRS and the credits provided in Section 38 of the Code should be normalized for ratemaking purposes;

(26) any motions or objections made by any party hereto during the course of these proceedings which are unresolved should be resolved in a manner consistent with the findings of fact and ultimate conclusions herein contained.

IT IS THEREFORE ORDERED by the Commission that the Suspension Order entered March 10, 1982, and the Resuspension Order entered July 14, 1982, be, and they are hereby, vacated and set aside.

IT IS FURTHER ORDERED that the tariff sheets containing rate schedules proposing a general increase in electric and gas rates filed by Respondent on February 19, 1982 be, and they are hereby, permanently cancelled and annulled.

IT IS FURTHER ORDERED that Respondent be, and it is hereby, directed to prepare and file with this Commission tariff sheets for electric and natural gas service conforming with the provisions of Findings (19), (20) and (22) herein together with other applicable provisions of this Order, which will enable Respondent reasonably to obtain the electric and gas operating results approved herein; said electric and gas tariff sheets to become effective within five (5) calendar days after filing same with this Commission for service rendered on and after the effective date of the tariff, with individual tariff sheets to be corrected within that time period, if necessary.

IT IS FURTHER ORDERED, pursuant to Section 14 of the Illinois Public Utilities Act, that Respondent be directed to place into effect effective January 1, 1983, the gas utility depreciation rates found to be proper and adequate in this proceeding.

IT IS FURTHER ORDERED that Respondent be, and it is hereby, authorized and directed to take all steps necessary to obtain all tax benefits pursuant to all appropriate and relevant accounting and normalization requirements of the Economics Recovery Tax Act of 1981, Accelerated Cost Recovery System Section 168(e)(3) and Section 46(f).

IT IS FURTHER ORDERED that Respondent be, and it is hereby, directed and required to file detailed expense reduction plans with the Commission's Chief Clerk within sixty (60) days of the date of this Order.

IT IS FURTHER ORDERED that any motions or objections made by any party hereto during the course of these proceedings which are unresolved be, and they are hereby, resolved in a manner consistent with the findings of fact and ultimate conclusions contained in this Order.

By Order of the Commission this 12th day of January, 1983.

(SIGNED) MICHAEL V. HASTEN

Chairman

(S E A L)

Commissioner Andrew C. Barrett dissenting in part, as to construction work in progress; a written opinion will be filed.

Commissioner Daniel Rosenblum dissenting:

I cannot support the Commission's decision to grant an excessively large increase to Illinois Power. The decision is not supported by the record. The decision is contrary to sound regulatory theory. The decision fails to balance the interests of ratepayers and shareholders.

The Commission should have refused to allow the addition of any additional construction work in progress (CWIP). The Commission should also have authorized a slightly lower rate of return on equity of 15.25 percent. The result would have been a financially stable utility and a rate increase more than $50 million smaller than that authorized today.

The decision is premised on the assumption that it is advantageous to authorize sufficient revenues to maintain Illinois Power's current bond rating. Analysis of various financial ratios suggests that an increase in the range of that approved today is necessary to maintain the current rating.

The Commission's decision might have been reasonable if the record demonstrated that the costs of maintaining the current bond rating were justified by the benefits to ratepayers. There is no such demonstration. It is one thing to state that, all other things being equal, an AA rating is better than an A rating. There is no cost benefit analysis, however, proving that it is in the ratepayer's best interest to maintain the current ratings. There is also no other justification for the size of today's increase.

Since the increment of CWIP allowed into rate base in today's decision is in large part an attempt to provide the revenues necessary to maintain current bond ratings, the failure to prove the necessity of maintaining those ratings eliminates the support for the additional CWIP.

It should be observed that inclusion of additional CWIP is not consistent with the criteria set forth in the most recent Illinois Power Rate Order, Docket No. 80-0544 (July 1, 1981), where the Commission stated at page 33:

> The Commission views the investment of funds in CWIP as used and useful to the benefit of the customer which may be included as a component of the rate base when, pursuant to a certificate of convenience and necessity granted by the Commission for construction of such a plant, the investment grows to a point where its significance is so great that it could impair financing. To what extent such investment, if any, should be included in the rate base for a particular public utility, must, however, be determined by the specific circumstances in each rate proceeding and will be considered by the Commission on a case-by-case basis.

The crucial point is that there is no showing that additional CWIP is necessary in order to avoid the threat of "impaired financing". In fact, with Illinois Power's current ratings, it is absolutely clear that Illinois Power is in no danger of having its ability to finance impaired.

An argument can be made that additional CWIP should be included, whether or not justified by financial ratios and bond ratings, because there is a reduction in total revenue requirements in connection with the project under construction. This argument has merit only for those ratepayers with discount rates in excess of Illinois Power's.

It is necessary to balance the interests of Illinois Power and its ratepayers and, more specifically, the interests of those

ratepayers with relatively high discount rates versus those with relatively low discount rates.

Those ratepayers with high discount rates ne our protection far more than those with lower discount rates. In more human terms, it is the unemployed and the underemployed who need our protection. Families living on unemployment insurance and public assistance, or on rapidly dwindling savings, cannot afford to invest in the future savings which might result from inclusion of additional CWIP or the maintenance of a high bond rating. The Commission's myopic focus on bond ratings and financial ratios has blinded it to the reality that many of Illinois Power's ratepayers simply cannot afford to pay now to save later.

Finally, the Commission's decision does not advance the proper goals of regulation. It certainly does not simulate the free market. In the free market, to the extent it exists, a company as overextended as is Illinois Power, with its massive over budget and delayed construction program, would never expect to have bond ratings as high as those of Illinois Power. Its shareholders could never expect to earn a net income rate of return in excess of 18 percent. Its shareholders would not have a regulatory agency to insulate them from risk and to pass those risks on to customers.

The Commission's reliance on "financial ratio" or "net income" regulation actually reduces the ability to regulate properly. Financial ratio regulation makes almost meaningless the distinction between "above the line" and "below the line" expenses. It makes little difference whether an expense is disallowed, when the Commission is focusing on cash flow and will simply compensate for the disallowed expense elsewhere. In fact, a company may benefit if enough expenses are disallowed. The Commission may find it necessary to raise the rate of return on equity which, according to the majority's policy, will result in an increase in the AFUDC rate to the detriment of future rate payers. (When construction is completed and Illinois Power sees the possibility of earning a rate of return on its expanded rate base it is highly unlikely that we will see requests for financial ratio regulation.)

The Commission's focus on financial ratios also lessens the ability to respond to changes in the market. While required rates of return have decreased based on current market conditions, that decrease is not reflected in the financial ratios which determine the size of the "required" increase. (A more thorough analysis utilizing current market conditions may indicate that financial ratios do change with changes in the market, however, that analysis is not in the record.)

The overall effect of financial ratio regulation is an inability to balance interests. The effect of such regulation, whether or not intentional, is to shift risk to the ratepayer and to reward shareholders.

Thus, Illinois Power's shareholders are treated as though its management decisions regarding Clinton I warrant the advantages of its current bond rating, while ratepayers pay substantially higher rates.

My reasons for dissenting are best illustrated by Illinois Power's 1982 Lincoln Continental. The Commission, on page 23 of the Order, properly found that "...the luxury automobile creates an appearance of indifference to the economic circumstances of Illinois Power's ratepayer." Unfortunately, even if the amount were not too trivial to make a difference, the adjustment ordered by the Commission could not affect the rate increase in this case because of the focus on financial ratios and bond ratings. The real problem is that Illinois Power's AA- and Aa3 ratings are luxuries which ratepayers do not need and cannot afford. Au-

thorizing a rate increase designed to maintain these "Lincoln Continental" bond ratings creates an appearance of indifference to the dire financial straits of many of Illinois Power's ratepayers.

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

CERTIFICATE

Re: 82-0152

I, ROSE M. CLAGGETT, do hereby certify that I am Chief Clerk of the Illinois Commerce Commission of the State of Illinois and keeper of the records and seal of said Commission.

I further certify that the above and foregoing is a true, correct and complete copy of order made and entered of record by said Commission on January 12, 1983.

Given under my hand and seal of said Illinois Commerce Commission at Springfield, Illinois, on January 13, 1983.

Rose M. Claggett

Chief Clerk

Ill. C. C. No. 27
Eighth Revised Sheet No. 1
Cancelling Ill. C. C. No. 27
Seventh Revised Sheet No. 1

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

TABLE OF CONTENTS

*Asterisk indicates change.

Issued May 31, 1983
Filed Pursuant to
Illinois Commerce Commission
Order in Docket 82-0488
Dated May 11, 1983.

Issued by Larry D. Haab
Vice President
Decatur, Illinois

Effective June 6, 1983

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

STANDARD TERMS AND CONDITIONS

The Standard Terms and Conditions set forth below and Ill. C. C. No. 24 - Rules, Regulations and Conditions Applying to Electric Service apply to all pertinent electric service classifications and riders, except that where provisions not consistent herewith or with the above-mentioned rules, regulations and conditions are set out in individual service classification, riders and special contracts on file with the Illinois Commerce Commission the provisions of the service classifications, riders and special contracts shall govern.

1. Resale and Redistribution

Energy supplied to any Customer under Ill. C. C. No. 27 is not available for resale or redistribution.

2. Exclusive Source of Power

Service shall not be available to any Customer where Customer purchases electric energy from any other source than Utility.

3. Modification of Schedule of Rates and Contracts

Any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, any substitution therefore, and any existing or future contract required by a service classification to be entered into between Utility and Customer for electric service shall be amended from time to time to incorporate any revisions and changes in the particular service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service (including without limitation changes in rates, charges, and terms or conditions of service) when such revision, change or substitution shall be approved or permitted to go into effect under the Public Utilities Act or as otherwise provided by law. Nothing contained in any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract, shall affect or be construed as affecting in any way the right of Utility unilaterally and without consent of Customer to take or initiate action, as permitted by applicable laws and regulations, to make revisions or changes in any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract.

*4. Terms of Payment

(a) Customer's bills will be rendered at monthly intervals bearing the date on which net payments are due, namely not less than 21 days after date distributed for residential customers and 14 days for non-residential customers excepting those non-residential customers in Subsection 4(d). Utility will assess a late payment charge in an amount equal to 1½% per month on any amount, including amounts previously past due, for utility service which is considered past due.

(b) Utility will, in accordance with the Commission's General Order 172, extend the date on which payment is due by up to 10 days in those circumstances and for those residential customers specified in the General Order. Utility may recertify those residential customers annually to insure they still qualify for the 10 day extension.

(c) Utility shall automatically waive the additional charge of 1½% for bills paid after the due date provided such allowances are not made more often than once every six months.

(d) Utility will not assess a late payment charge on the amounts owing from Federal, State, County and local governments (including, but not limited to townships, municipalities and school districts) until 45 days from the date of the issuance of the bill for utility service, except that the provisions of "An Act to require prompt payments by the State of Illinois for goods or services" (Ill. Rev. Stat. 1981, ch. 127, par. 132.401 et seq.), as amended, control in the situations to which the Act applies.

(e) The late payment charge provided for in subsection 4(a) above shall not be in lieu of or affect Utility's right to collect interest as provided by law or by contract on account of failure of Customer to pay charges when they become due and payable.

*Asterisk indicates change.

Issued September 30, 1983
Filed Pursuant to
Illinois Commerce Commission
Order in Docket 82-0591
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Issued by Larry D. Haab
Senior Vice President
Decatur, Illinois

Effective November 1, 1983

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

STANDARD TERMS AND CONDITIONS - PAGE 2

*5. Additional Charges for State Revenue Taxes

State Public Utility Tax of 5% and Illinois Commerce Commission Gross Revenue Tax of 0.08% on electric service will be added to the billing as provided in Section 36 of the Public Utilities Act, as amended, as stated in Rider AA of Utility's Schedule of Rates for Electric Service.

6. Additional Charges for Municipal Tax

Whenever and so long as any municipal or quasi-municipal corporation shall impose the tax authorized by Section 8-11-2 of the Illinois Municipal Code, as amended, Utility shall, pursuant to Section 36 of the Public Utilities Act, as amended, add certain additional charges for services rendered in such municipalities. The municipalities in which such charges shall be applicable and the amount of such additional charges shall be as stated in Rider A of Utility's Schedule of Rates for Electric Service.

7. Additional Charges for Service in Certain Communities

Whenever and so long as any municipal or quasi-municipal corporation shall require Utility to pay a consideration for any franchise or privilege, or shall tax Utility as may be provided by law, and if such consideration or tax is based on a percentage of Utility's gross earnings or gross receipts from electric service to Customers within the territorial limits of such taxing bodies, the charge for service to each Customer within such territorial limits which would otherwise be made shall be increased (by separate billing item or items) by the same percentage or amount plus such additional percentage or amounts to cover costs of accounting, the resulting increases in other taxes and other matters as may be permitted by law.

8. Additional Charges for Not Sufficient Fund Checks

(a) When more than one NSF (Not Sufficient Funds) check is received by Utility within a twelve (12) month period from a residential customer, Utility shall assess a charge of $5.00 for the second and each subsequent occurrence.

(b) Utility shall assess a charge of $5.00 when non-residential customer's check is returned to Utility for NSF.

(c) Upon receipt of three NSF checks within a twelve (12) month period, Customer may be placed on a "cash basis". In such case, Utility shall require payment to be made by United States Currency, Money Order or Certified Check.

9. Additional Charges for Residential Service (RCS) Energy Audit

Residential customers who receive an energy audit under the Illinois Residential Conservation Service Program Plan shall pay Utility, in advance, a charge of fifteen dollars ($15.00).

*Asterisk indicates change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

INDEX OF COMMUNITIES SERVED

This index of communities served is applicable to Utility's Schedule of Rates for Electric Service and Rules, Regulations and Conditions Applying to Electric Service set forth in Ill. C. C. Nos. 27 and 24, respectively.

BELLEVILLE SERVICE AREA

Belleville District:	Belleville	East Carondelet	Maeystown	Scott Field (U)
	Burksville (U)	Fayetteville	Millstadt	Shiloh
	Cahokia (Part)	Floraville (U)	New Athens	Smithton
	Centreville	Harrisonville (U)	New Hanover (U)	Swansea
	Columbia	Hecker	O'Fallon	Valmeyer
	Darmstadt (U)	Lenzburg	St. Libory	Wartburg (U)
	Dupo			
Trenton District:	Albers	Damiansville (U)	Lebanon	St. Rose (U)
	Aviston	Germantown	New Baden	Summerfield
	Bartelso	Jamestown (U)	New Memphis (U)	Trenton
	Beckemeyer			

BLOOMINGTON SERVICE AREA

Bloomington District:	Bloomington	Downs	Gridley	Meadows (U)
	Carlock	Ellsworth	Hudson	Normal
	Chenoa	El Paso	Kappa	Panola
	Colfax	Flanagan	Lake Bloomington(U)	Secor
	Congerville	Funks Grove (U)	Le Roy	Shirley (U)
	Cooksville	Goodfield	Lexington	Stanford
	Danvers	Graymont (U)	Mackinaw	Towanda

CHAMPAIGN SERVICE AREA

Champaign District:	Bondville	Mahomet	Royal	Thomasboro
	Champaign	Mansfield	Savoy	Urbana
	Lodge (U)	Mayview (U)	Seymour (U)	White Heath(U)
Monticello District:	Monticello			

DANVILLE SERVICE AREA

Danville District:	Belgium	Fithian	Muncie	Sidell
	Bunsenville (U)	Georgetown	Ogden	Tilton
	Chrisman	Grape Creek (U)	Olivet (U)	Vermilion Grove (U)
	Collison (U)	Hegeler (U)	Ridge Farm	Westville
	Danville	Indianola	Scottland (U)	

DECATUR SERVICE AREA

Clinton District:	Clinton	De Witt	Maroa	Weldon
	Deland	Lane (U)	Wapella	
Decatur District:	Argenta	Dawson	Illiopolis	Mt. Auburn
	Boody (U)	Decatur	Lake City (U)	Mt. Zion
	Buffalo	Elwin (U)	Lanesville (U)	Niantic
	Casner (U)	Forsyth	La Place (U)	Oakley (U)
	Cerro Gordo	Harristown	Mechanicsburg	Oreana
	Cisco	Hervey City (U)	Milmine (U)	Warrensburg
	Dalton City			

(U) Unincorporated

Issued July 2, 1981 Effective July 3, 1981

Issued by Larry D. Haab
Vice President
Decatur, Illinois

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

INDEX OF COMMUNITIES SERVED - PAGE 2

GALESBURG SERVICE AREA

Aledo District:	Aledo	Joy	North Henderson	Shale City (U)
	Alexis	Keithsburg	Norwood (U)	Viola
	Alpha	New Boston	Rio	Wanlock (U)
	Burgess (U)	(New) Windsor	Seaton	Woodhull
	Gilchrist (U)			
Galesburg District:	Abingdon	Galesburg	Hermon (U)	Prairie City
	Avon	Gilson	Knoxville	St. Augustine
	De Long	Greenbush (U)	Lake Bracken (U)	Wataga
	East Galesburg	Henderson		
Kewanee District:	Altona	Elmira (U)	Mineral	Osceola (U)
	Annawan	Galva	Nekoma (U)	Sheffield
	Atkinson	Kewanee	Neponset	Ulah (U)
	Bishop Hill	La Fayette	New Bedford	Victoria
	Buda	Lake Calhoun (U)	Oneida	Wyanet
	Cambridge	Manlius		
Monmouth District:	Berwick (U)	Gladstone	Little York	Raritan
	Biggsville	Good Hope	Lomax	Sciota
	Blandinsville	Gulfport	Media	Smithshire (U)
	Cameron (U)	Kirkwood	Monmouth	Stronghurst
	Carman (U)	La Harpe	Oquawka	Terre Haute (U)
	Gerlaw (U)			

GRANITE CITY SERVICE AREA

Collinsville District:	Caseyville	Grantfork	Marine	St. Jacob
	Collinsville	Hollywood Heights (U)	Maryville	Troy
	Fairview Heights (Part)			
Edwardsville District:	Edwardsville	Hamel	Poag (U)	Worden
	Glen Carbon			
Granite City District:	Brooklyn	Madison	Pontoon Beach	Venice
	Granite City	National City		
Wood River District:	Bethalto	Moro (U)	Roxana	Wanda (U)
	Cottage Hills (U)	Prairietown (U)	South Roxana	Wood River
	East Alton	Rosewood Heights (U)		

HILLSBORO SERVICE AREA

Carlinville District:	Atwater (U)	Carlinville	Nilwood	Standard City
Gillespie District:	Benld	Dorchester	Gillesipie	Sawyerville
	Brighton	Eagarville	Lake Gillespie (U)	Wilsonville
	Bunker Hill	East Gillespie	Mt. Clare	Woodburn (U)
Greenville District:	Greenville	Mulberry Grove	Pleasant Mound (U)	Smithboro
	Hookdale (U)	Pierron	Pocahontas	Tamalco (U)
	Keyesport			
Hillsboro District:	Butler	Fillmore	New Douglas	Sorento
	Chapman (U)	Hillsboro	Panama	Taylor Springs
	Coffeen	Irving	Schram City	Witt
	Donnellson			
Litchfield District:	Clarksdale (U)	Litchfield	Palmer	Raymond
	Harvel	Morrisonville		

(U) Unincorporated

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Vice President
Decatur, Illinois

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

INDEX OF COMMUNITIES SERVED - PAGE 3

HILLSBORO SERVICE AREA - Continued

Staunton District:	Alhambra Livingston	Mt. Olive Staunton	White City	Williamson
Vandalia District:	Bayle City (U) Bingham Bluff City (U)	Brownstown Hagarstown (U) Herrick	Ramsey Shobonier (U)	Vandalia Vernon

JACKSONVILLE SERVICE AREA

Jacksonville District:	Arcadia (U) Arenzville	Chapin Concord	Jacksonville Lynnville	Sinclair (U) South Jacksonville

LA SALLE SERVICE AREA

La Salle District:	Arlington Bureau Junction Cherry Dalzell De Pue Dover Granville	Hennepin Hollowayville Kasbeer(U) La Moille La Salle Magnolia Malden	Mark McNabb Mt. Palatine (U) North Utica Peru Seatonville Spring Valley	Standard Tiskilwa Triumph (U) Troy Grove Van Orin (U) Zearing (U)
Ottawa District:	Dayton (U) Harding (U) Marseilles	Milbrook (U) Millington Naplate	Newark Norway (U) Ottawa	Serena (U) Sheridan Wedron (U)

*MT. VERNON SERVICE AREA

Centralia District:	Central City Centralia Ferrin (U) Hoffman	Huey Irvington Junction City Patoka	Posey Raccoon Lake (U) Richview Sandoval	Shattuc (U) Walnut Hill Wamac
Eldorado District:	Eldorado Enfield Equality	Junction Old Shawneetown	Raleigh Ridgway	Shawneetown Texas City (U)
Mt. Vernon District:	Addieville Ashley Beaucoup (U) Bluford	Bonnie Dix Hoyleton Huegely (U)	Mt. Vernon Nashville Nason New Minden	Okawville Venedy Waltonville Woodlawn
Salem District:	Cartter (U)	Kell	Odin	Salem
Chester District:	Bremen (U)	Chester		
Du Quoin District:	Du Bois Du Quoin	Holden (U) Pinckneyville	St. Johns Sunfield (U)	Tamaroa
Sparta District:	Ava Baldwin Campbell Hill Clarmi.. (U) Coulterville Cutler Ellis Grove	Evansville Marissa Modoc (U) Oakdale (U) Percy Prairie du Rocher	Preston Red Bud - Suburban Reily Lake (U) Renault (U) Ruma Schuline (U)	Sparta Steeleville Swanwick (U) Tilden Walsh (U) Willisville

(U) Unincorporated

*Asterisk indicates change.

Issued February 10, 1983

Effective March 14, 1983

Issued by Larry D. Haab
Vice President
Decatur, Illinois

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 1
Residential Service - Small Use

1. Availability

Any customer located in territory served by Utility may take service under this service classification subject to the following conditions:

(a) that the predominant use is for domestic purposes in single occupancy, in a one unit apartment or residence, or is for general farm purposes, and

(b) that the energy delivered is not resold or redistributed, and

(c) that Customer's average daily usage during any three of the four billing periods in the prior summer season has been less than 15 kwh per day, and

(d) that Customer has taken residential service for one complete summer season.

The conditions set forth in (c) and (d) above are satisfied for initial service if met by the preceding occupant of the premises served.

2. Conditions of Service

Only single phase service will be provided.

*3. Rates

(a) Facilities Charge $5.00 per month

(b) Energy Charge

The following charges shall apply to all usage for bills issued during the following seasons:

Summer Season (1)		Winter Season (2)	
Kilowatt hours (kwh) Used in Any One Month	Charges	Kilowatt hours (kwh) Used in Any One Month	Charges
For all kwh	6.74c per kwh	For the first 225 kwh	5.70c per kwh
		For all over 225 kwh	3.79c per kwh

(1) Summer Season is the first billing period having an ending meter reading date on or after June 15 and the 3 succeeding monthly billing periods.

(2) Winter Season is all billing periods not in the summer season.

(c) Fuel Cost Adjustment

The energy charges in subsection 3(b) are subject to the Fuel Cost Adjustment provided in Rider F.

NOTE: This service classification is subject to Utility's Standard Terms and Conditions in its Schedule of Rates for Electric Service.

*Asterisk indicates change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 2
Residential Service

*1. Availability

Any customer located in territory served by Utility may take service under this service classification subject to the following conditions:

(a) that the predominant use is for domestic purposes in single occupancy, in a one unit apartment or residence, or is for general farm purposes, and

(b) that the energy delivered is not resold or redistributed, and

(c) that Customer's average daily usage during any three of the four billing periods in the prior summer season has been less than 150 kwh per day, provided that any customer served under Service Classification 3 may not be served under this service classification if customer's average daily usage in any summer billing period in the prior summer season was equal to or greater than 125 kwh per day.

2. Conditions of Service

Single phase service. Three phase service may be provided under the terms and conditions of Utility's Rules, Regulations and Conditions Applying to Electric Service.

*3. Rates

(a) Facilities Charge — $6.50 per month for single phase service; $11.50 per month for three phase service

(b) Energy Charge

The following charges shall apply to all usage for bills issued during the following seasons:

Summer Season (1) Kilowatt hours (kwh) Used in Any One Month	Charges	Winter Season (2) Kilowatt hours (kwh) Used in Any One Month	Charges
For all kwh	6.74¢ per kwh	For the first 825 kwh	5.70¢ per kwh
		For all over 825 kwh	3.79¢ per kwh

(1) Summer Season is the first billing period having an ending meter reading date on or after June 15 and the 3 succeeding monthly billing periods.

(2) Winter Season is all billing periods not in the summer season.

(c) Fuel Cost Adjustment

The energy charges in subsection 3(b) are subject to the Fuel Cost Adjustment provided in Rider F.

NOTE: This service classification is subject to Utility's Standard Terms and Conditions in its Schedule of Rates for Electric Service.

*Asterisk indicates change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 3
Residential Service - Large Use

*1. Availability

Any Customer located in territory served by Utility may take service under this service classification subject to the following conditions:

(a) that the predominant use is for domestic purposes in single occupancy, in a one unit apartment or residence, or is for general farm purposes, and

(b) that the energy delivered is not resold or redistributed, and

(c) that Customer's average daily usage during any two or more of the four billing periods in the prior summer season has been equal to or greater than 150 kwh per day. Summer Season is the first billing period having an ending meter reading date on or after June 15 and the three succeeding monthly billing periods. Any Customer served under this service classification shall continue to be served under this service classification so long as Customer's average daily usage during any monthly billing period in the prior summer season is equal to or greater than 125 kwh per day.

(d) any Customer not taking service pursuant to subsection 1(c) may elect to take service under this service classification. If such Customer withdraws from this service classification during the first twelve months of service, Customer shall pay Utility $15.00 plus $5.00 per month for each month of the initial twelve month period that Customer did not remain on Service Classification 3.

2. Conditions of Service

Single phase service. Three phase service may be provided under the terms and conditions of Utility's Rules, Regulations and Conditions Applying to Electric Service.

*3. Rates

(a) Facilities Charge — $11.50 per month for single phase service; $16.50 per month for three phase service

(b) Demand Charge

The following charges shall apply to each kw of billing demand for bills issued during the following seasons:

Kilowatts (kw) of Billing Demand Established in Any One Month (3)	Charges
Summer Season (1)	$7.80 per kw
Winter Season (2)	$1.40 per kw

(1) Summer season is the first billing period having an ending meter reading date on or after June 15 and the 3 succeeding monthly billing periods.

(2) Winter season is all billing periods not in the summer season.

(3) The billing demand in kw is equal to the highest number of kwh used during any one hour in an on-peak period, as defined in subsection 3(c)(1), during the billing period.

*Asterisk indicates change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 3 - PAGE 2

*3. Rates (continued)

(c) Energy Charge

The following charges shall apply to all usage for bills issued:

For all kwh used during on-peak periods (1)	For all kwh used during off-peak periods (2)
3.50¢ per kwh	2.50¢ per kwh

(1) The on-peak period is the 11 consecutive hours commencing at 10:00 a.m. and ending at 9:00 p.m., on Monday through Friday excluding New Year's Day, Good Friday, Memorial Day (May 30), July 4, Labor Day, Thanksgiving Day, Christmas Eve Day and Christmas Day.

(2) The off-peak period is all hours not in the on-peak period.

(d) Fuel Cost Adjustment

The energy charges in subsection 3(c) are subject to the Fuel Cost Adjustment provided in Rider F.

NOTE: This service classification is subject to Utility's Standard Terms and Conditions in its Schedule of Rates for Electric Service.

*Asterisk indicates change.

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Filed Pursuant to
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Order in Docket 82-0152
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Issued by Larry D. Haab
Vice President
Decatur, Illinois

Effective January 18, 1983

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

CANCELLATION SHEET

Issued January 13, 1983
Filed Pursuant to [illegible]
Illinois Commerce [illegible]ssion
Order in Docket 82-[illegible]2
Dated January 12, 1983.

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Issued by Larry D. Haab
Vice President
Decatur, Illinois

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 10
General Service - Small Use

*1. Availability

Any Customer located in territory served by Utility may take service under this service classification subject to the following conditions:

(a) that the energy delivered is not resold or redistributed, and

(b) that Customer's average daily usage has not equaled or exceeded 61 kwh per day during any billing period in the most recent summer season.

2. Conditions of Service

(a) Only single phase service will be provided.

(b) Utility will provide and maintain all facilities necessary to deliver one standard delivery voltage at one specified location and to measure the use of energy at the delivery voltage to Customer. Customer shall provide all necessary facilities for utilization of service at the specified standard delivery voltage and for receipt of such service at a single point of delivery.

*3. Rates

(a) Facilities Charge $10.00 per month

(b) Energy Charge

The following charges shall apply to all usage for bills issued during the following seasons:

Summer Season (1)		Winter Season (2)	
Kilowatt hours (kwh) Used in Any One Month	Charges	Kilowatt hours (kwh) Used in Any One Month	Charges
For all kwh	8.44c per kwh	For the first 1300 kwh	6.21c per kwh
		For all over 1300 kwh	3.20c per kwh

(1) Summer Season is the first billing period having an ending meter reading date on or after June 15 and the 3 succeeding monthly billing periods.

(2) Winter Season is all billing periods not in the summer season.

(c) Fuel Cost Adjustment

The energy charges in subsection 3(b) are subject to the Fuel Cost Adjustment provided in Rider F.

NOTE: This service classification is subject to Utility's Standard Terms and Conditions in its Schedule of Rates for Electric Service.

*Asterisk indicates change.

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Vice President
Decatur, Illinois

Effective January 18, 1983

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 21
Demand Metered General Service

*1. Availability

Any Customer located in territory served by Utility may take service under this service classification subject to the following conditions:

(a) that the energy delivered is not resold or redistributed, and

(b) that Customer's contract capacity, as defined in this service classification, is less than 400 kw.

2. Conditions of Service

(a) Service will be delivered to Customer at no more than one of the following standard delivery voltages:

(1) Secondary service
Single phase service - 3 wire
120/240 volts
120/208 volts
Three phase service - 3 wire
240 or 2400 volts, delta connected
480 volts, delta or ungrounded wye connected
Combined single phase and three phase service
120/208 or 277/480 volts, wye connected
120/240 volts single phase, 240 volts three phase, delta connected

(2) Primary service, as available
2400/4160 or 7200/12,470 volts, wye connected

(3) Other standard voltages will be provided by Utility, as available, under terms of Utility's Rules, Regulations and Conditions Applying to Electric Service.

(b) Utility will provide and maintain all facilities necessary to deliver one standard delivery voltage at one specified location to Customer. Customer shall provide all necessary facilities for utilization of service at the specified delivery voltage and for the receipt at a single point of delivery. Where both single and three phase service is required, Customer shall provide the necessary wiring for Utility to measure both single and three phase service through a single meter.

(c) Utility will normally measure Customer's service at the delivery voltage. In the event Utility requires measurement of Customer's service at a voltage other than the delivery voltage, the measured demand and energy consumption shall be increased or decreased by one percent to compensate for transformer losses.

*3. Rates

(a) Facilities Charge — $15.00 per month for single phase service; $19.00 per month for three phase service

(b) Transformation Charge

(1) If Utility installs transformers to transform the voltage from Utility's available distribution voltage to the service voltage desired by Customer, the monthly charge shall be $0.48 per kw of transformation capacity.

(2) Customer's transformation capacity shall be the highest measured demand of Customer during any billing period, but not less than 10 kw.

*Asterisk indicates change.

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Vice President
Decatur, Illinois

Effective January 18, 1983

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 11 - PAGE 2

*3. Rates (continued)

(c) Energy Charge

The following charges shall apply to all usage for bills issued during the following seasons:

Summer Season (1)

Kilowatt hours (kwh) Used in Any One Month	Charges
For the first 250 kwh used per kw of contract capacity	8.14c per kwh
For all kwh in excess of 250 kwh used per kw of contract capacity	2.80c per kwh

Winter Season (2)

Kilowatt hours (kwh) Used in Any One Month	Charges
For the first 175 kwh used per kw of contract capacity	5.91c per kwh
For all kwh in excess of 175 kwh used per kw of contract capacity	2.80c per kwh

(1) Summer Season is the first billing period having an ending meter reading date on or after June 15 and the 3 succeeding monthly billing periods.

(2) Winter Season is all billing periods not in the summer season.

(d) Fuel Cost Adjustment

The energy charges in subsection 3(c) are subject to the Fuel Cost Adjustment provided in Rider F.

(e) Determination of Contract Capacity

A contract capacity of not less than 10 kw shall be determined based on load data supplied by Customer prior to taking service under this service classification. Customer's contract capacity shall be increased, or decreased, without notice or other action, to Customer's maximum demand during any summer season billing period occurring during the twelve consecutive billing periods ending with the current billing period, but not less than 10 kw.

(f) Time-of-Day Demand Metering Option

Customer may elect to have Utility install a meter which will measure demands during the 11 consecutive hours of 10:00 a.m. through 9:00 p.m. on Monday through Friday during the period of June 15 through September 14, but excluding July 4 and Labor Day. If Customer so elects, the demands as registered by this meter will be used for the establishment of Customer's contract capacity as provided for in subsection 3(e) hereof. Customer electing this option shall pay an additional charge of $5.00 per month.

*4. Additional Conditions and Contract Provisions

(a) In the event Customer shall cease all operations and discontinue business at the location at which service is being rendered under any contract, Customer may, upon not less than 30 days written notice to Utility, cancel the contract then in effect at the beginning of any billing period commencing after the expiration of the primary term.

*Asterisk indicates change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 11 - PAGE 3

*4. Additional Conditions and Contract Provisions (continued)

(b) Any existing or future contract required by this service classification to be entered into or entered into between Utility and Customer for electric service shall be amended from time to time to incorporate any revisions and changes in this service classification, rider or any standard terms or conditions, or rule, regulation or condition applying to electric service (including without limitation changes in rates, charges, and terms or conditions of service) when such revision, change or substitution shall be approved or permitted to go into effect under the Public Utilities Act or as otherwise provided by law. Nothing contained in any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract shall affect or be construed as affecting in any way the right of Utility unilaterally and without consent of Customer to take or initiate action, as permitted by applicable laws and regulations, to make revisions or changes in any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract.

NOTE: This service classification is subject to Utility's Standard Terms and Conditions in its Schedule of Rates for Electric Service.

*Asterisk indicates change.

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Vice President
Decatur, Illinois

Effective January 18, 1983

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 13
Unmetered General Service

1. Availability

Any Customer located in territory served by Utility may take service under this service classification for billboards, phone booths, traffic signals, warning lights of all types and amplifier systems installed along public communication systems where the operation is on a continuous basis or in the case of lighting services, where such service is controlled by a photo-electric cell.

2. Conditions of Service

(a) Only single phase service will be provided.

(b) Customer's connected load at any one location shall not exceed 10 kw.

(c) Line extensions will be made in accordance with Utility's Rules, Regulations and Conditions Applying to Electric Service.

(d) Utility will furnish, install and operate the necessary service drop. Customer shall furnish and install the necessary fuses to protect Customer's equipment. The point of delivery to Customer shall be at the point of connection of Utility's service drop to Customer's facilities.

(e) Customer shall furnish, install, operate and maintain all other service facilities and equipment that may be required in order to take service from Utility at a particular location. Where the operation of Customer's facilities are to be controlled by a photo-electric cell, Utility shall furnish, install and maintain the cell at its cost and expense. Utility shall have the right to inspect and test Customer's facilities and Customer shall permit Utility access to Customer's premises for such purposes.

(f) Customer agrees not to increase connected load or change the character of facilities without, in each case, providing not less than 30 days written notice to Utility.

*3. Rates

(a) Facilities Charge — $6.00 per month for each point of delivery

(b) Energy Charge

All service rendered shall be billed monthly at the following energy charges:

Non-Controlled Unmetered Service

For all kwh — 3.95c per kwh

Unmetered Service Controlled by a Photo-Electric Cell

For all kwh — 2.94c per kwh

The kwh consumed by Customer in each month shall be determined by multiplying the kw of connected load (including any auxiliary equipment) as estimated by Utility on the basis of appropriate tests and rated capacity of the connected load by one-twelfth of the annual hours of operation as estimated by Utility.

(c) Fuel Cost Adjustment

The energy charges in subsection 3(b) are subject to the Fuel Cost Adjustment provided in Rider F.

*Asterisk indicates change.

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SERVICE CLASSIFICATION 13 - PAGE 2

*4. Additional Conditions and Contract Provisions

(a) Customer shall be required to enter into a written contract for service for a primary term of not less than one year. The primary term shall be automatically extended from year to year with the privilege of either party to terminate the contract at the end of the primary term or at any time during any extended term on not less than 30 days written notice. If Customer terminates the contract within the primary or extended term, Customer shall pay Utility a sum equal to the monthly facilities charge and charges for any leased facilities, multiplied by the number of months remaining in the term.

(b) Any existing or future contract required by this service classification to be entered into or entered into between Utility and Customer for electric service shall be amended from time to time to incorporate any revisions and changes in this service classification or any rider, standard term or condition, or rule, regulation or condition applying to electric service (including without limitation changes in rates, charges, and terms or conditions of service) when such revision, change or substitution shall be approved or permitted to go into effect under the Public Utilities Act or as otherwise provided by law. Nothing contained in any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract, shall affect or be construed as affecting in any way the right of Utility unilaterally and without consent of Customer to take or initiate action, as permitted by applicable laws and regulations, to make revisions or changes in any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract.

NOTE: This service classification is subject to Utility's Standard Terms and Conditions in its Schedule of Rates for Electric Service.

*Asterisk indicates change.

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Vice President
Decatur, Illinois

Effective January 18, 1983

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 21
Large Power Service

*1. Availability

Any Customer located in territory served by Utility may take service under this service classification subject to the following conditions:

(a) that customer is located adjacent to Utility's lines possessing capacity adequate to supply Customer's requirements in addition to the requirements of other Customers already receiving service from such lines, or that Utility shall have sufficient time before Customer shall require service to construct such lines, and

(b) that the energy delivered is not resold or redistributed, and

(c) that service is not available under this service classification where Customer purchases electric energy from any source other than Utility, and

(d) that any Customer generating a portion of Customer's electric energy requirements shall not operate equipment in parallel with Utility's facilities unless prior written permission to do so has been obtained from Utility, and

(e) that prior to the commencement of service, Customer with contract capacity in excess of 1,000 kw shall enter into a written contract with Utility in accordance with this service classification.

2. Conditions of Service

(a) Service shall be delivered to Customer at only one standard three phase or combination single and three phase delivery voltage as follows:

(1) Secondary service
240 or 2400 volts, delta connected
480 volts, delta or ungrounded wye connected
120/208 or 277/480 volts, wye connected

(2) Primary service, as available
2400/4160 or 7200/12470 volts, wye connected
34.5, 69 or 138 kv phase to phase

(b) Utility will provide and maintain all facilities necessary to deliver one standard delivery voltage at one specified location to Customer. Customer shall provide all necessary facilities for utilization of service at the specified delivery voltage and for the receipt at a single point of delivery. Where both single and three phase service is required, Customer shall provide the necessary wiring for Utility to measure both single and three phase service through a single meter.

(c) Utility will normally measure Customer's service at the delivery voltage. In the event Utility requires measurement of Customer's service at a voltage other than the delivery voltage, the measured demand and energy consumption shall be increased or decreased to compensate for transformer losses.

*Asterisk indicates change.

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ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

*3. Rates

(a) Demand Charges

(1) Monthly Demand Charge

The following demand charges shall apply to each kw of maximum on-peak demand occurring during the billing period for customer served from supply lines having the following voltage:

	138 kv, 69 kv & 34.5 kv	12.47 kv and below
Summer Season(i)		
For each kw of maximum on-peak demand	$9.50 per kw	$10.47 per kw
Winter Season(ii)		
For each kw of maximum on-peak demand up to 90% of customer's contract capacity	$4.97 per kw	$ 4.97 per kw
For all kw of maximum on-peak demand in excess of 90% of Customer's contract capacity	$2.42 per kw	$ 2.42 per kw

(i) Summer Season is the first billing period having an ending meter reading date on or after June 15 and the three succeeding billing periods.

(ii) Winter Season is all billing periods not in the Summer Season.

(iii) The on-peak period is the 11 consecutive hours commencing at 10:00 a.m. and ending at 9:00 p.m. on Monday through Friday excluding New Year's Day, Good Friday, Memorial Day (May 30), July 4, Labor Day, Thanksgiving Day, Christmas Eve Day and Christmas Day.

(iv) The off-peak period is all hours not in the on-peak period.

(2) Transformation Charge

(i) If Utility installs transformers to transform the voltage from Utility's available transmission or distribution voltage to the service voltage desired by Customer, the monthly charge shall be $0.48 per kw of transformation capacity.

(ii) Customer's transformation capacity shall be the highest measured demand of Customer during any billing period but not less than 430 kw.

(b) Energy Charge

(1) The following charges shall apply to all usage for bills issued for service from supply lines having the following voltages:

Kilowatt hours (kwh) Used in Any One Month	Charges 138 kv, 69 kv and 34.5 kv	12.47 kv and Below
For the first 100,000 kwh	4.14c per kwh	4.14c per kwh
For all over 100,000 kwh	3.30c per kwh	3.40c per kwh

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ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 21 - PAGE 3

*3. Rates (continued)

(2) Time-Of-Use Energy Credit

A credit of 1.00¢ per kwh shall apply to all kilowatthours used during the off-peak period in each month.

(i) The off-peak period for determination of an energy credit is the 13 consecutive hours commencing at 9:00 p.m. and ending at 10:00 a.m. on weekdays, all hours on the weekends and all hours on New Year's Day, Good Friday, Memorial Day (May 30), July 4, Labor Day, Thanksgiving Day, Christmas Eve Day and Christmas Day.

(ii) The on-peak period is all other hours not in the off-peak period.

(c) For any customer transferred to this service classification from Service Classification 11 on or after January 18, 1983, the sum of the monthly demand charge and the energy charge set forth in Section 3(a)(1) and 3(b) above shall not be greater than an average cost of 9.77¢ per kwh for a summer season billing period or 7.09¢ per kwh for a winter season billing period.

(d) Fuel Cost Adjustment

The energy charges in subsection 3(b) are subject to the Fuel Cost Adjustment provided in Rider F.

(e) Power Factor Adjustment

The following power factor adjustment provisions are applicable to all customers with a contract capacity in excess of 1,000 kw. The charges provided in subsection 3(a) are based on an average power factor during the period of maximum kw demand of 85% lagging. If the average power factor is between 85% lagging and 100% (unity), the charges shall be decreased 0.48¢ per kw of adjusted demand for each one percent or major fraction thereof that the average power factor exceeds 85% lagging. If the average power factor is less than 85% lagging, the charges shall be increased 0.73¢ per kw of adjusted demand for each one percent or major fraction thereof that the average power factor is less than 85% lagging. In cases of leading power factor, the adjustment shall be calculated as though the power factor were 100% (unity).

(f) Determination of Contract Capacity and Maximum On-Peak Demand

(1) The contract capacity shall be equal to customer's maximum on-peak demand occurring during the twelve consecutive billing periods ending with the current billing period, and occurring between June 15 and September 14, adjusted, if necessary, under the provisions of section 5 of Rider S. In no event shall a contract capacity be less than 400 kw.

(2) The maximum on-peak demand is the highest number of kw delivered during any 15 minute period of the on-peak period, defined in subsection 3(a)(1)(iii), in the billing period adjusted, if necessary, under subsection 2(c) hereof and/or provisions of section 4 of Rider S.

*4. Additional Conditions and Contract Provisions

(a) The contract with Utility shall specify a contract capacity. The primary term for the contract shall be determined as follows:

(1) Customers who are not taking service from Utility under the provisions of this or any other of Utility's service classifications shall contract for and take service for a primary term of 3 years, unless the contract capacity exceeds 1500 kw, in which case the primary term shall be 5 years.

(2) Customers taking service under the provisions of this or any other of Utility's service classifications who desire to contract for additional contract capacity may contract for and take service for a primary term equal to the remainder of the primary term of the contract under which service is being provided, but not less than one year; except that if Utility is required to install additional facilities to serve Customer's load, Customer and Utility shall enter into a new contract specifying the new contract capacity required by Customer. The new contract shall be for a term of years determined as follows, but not less than the remainder of the primary term of the present contract:

*Asterisk indicates change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 21 - PAGE 4

4. Additional Conditions and Contract Provisions (continued)

(i) One year if the new or added contract capacity required is less than 500 kw, or

(ii) Three years if the new or added contract capacity required is from 500 to 1500 kw, or

(iii) Five years if the new or added contract capacity required is greater than 1500 kw.

(b) Extension or termination of the term of any contract shall be determined as follows:

(1) The primary or extended term of any contract shall be automatically extended from year to year with the privilege of either party to terminate the contract at the end of the primary term or thereafter on not less than 30 days written notice.

(2) In the event Customer shall cease all operations and discontinue business at the location at which service is being rendered under such contract, Customer may, upon not less than 30 days written notice to Utility, cancel the contract then in effect at the beginning of any billing period commencing after the expiration of the primary term.

(c) Any existing or future contract required by this service classification to be entered into or entered into between Utility and Customer for electric service shall be amended from time to time to incorporate any revisions and changes in this service classification or any rider, standard term or condition, or rule, regulation or condition applying to electric service (including without limitation changes in rates, charges, and terms or conditions of service) when such revision, change or substitution shall be approved or permitted to go into effect under the Public Utilities Act or as otherwise provided by law. Nothing contained in any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract shall affect or be construed as affecting in any way the right of Utility unilaterally and without consent of Customer to take or initiate action, as permitted by applicable laws and regulations, to make revisions or changes in any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract.

NOTE: This service classification is subject to Utility's Standard Terms and Conditions in its Schedule of Rates for Electric Service.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 24
Annual Load Factor Large Power Service

1. Availability

Any Customer located in territory served by Utility may take service under this service classification subject to the following conditions:

(a) that Utility shall not be obligated to serve new Customer or additional load for existing Customers if Utility for any reason does not have available generating and transmission facilities adequate to serve such additional load, and

(b) that the energy delivered is not resold or redistributed, and

(c) that service is not available under this service classification where Customer purchases electric energy from any source other than Utility, and

(d) that any Customer generating a portion of Customer's electric energy requirements shall not operate equipment in parallel with Utility's facilities unless prior written permission to do so has been obtained from Utility, and

(e) that prior to the commencement of service, Customer shall enter into a written contract with Utility in accordance with this service classification.

2. Conditions of Service

(a) Service will be delivered to Customer from three phase electric lines having nominal standard voltages of either 34.5, 69 or 138 kv and possessing sufficient capability to supply the specified reserved capacity. Utility shall have the right to select the supply lines from which service will be rendered to Customer.

(b) Customer shall provide and maintain all transformers and related facilities necessary for supplying and utilizing the energy delivered.

(c) Utility will provide and maintain one three phase delivery voltage.

(d) Customer shall make available, without charge to Utility, space required for Utility's lines and delivery facilities.

(e) Utility will provide and maintain one point of delivery and metering equipment therefore, except as may be otherwise provided in Utility's Rules, Regulations and Conditions Applying to Electric Service. Such metering equipment shall be located on the high voltage side of transformation if transformation shall be required by Customer unless Utility elects to install such metering equipment on the low voltage side of transformation, in which case both the demand and energy consumption shall be increased to compensate Utility for transformer losses

*3. Rates

(a) Monthly Demand Charge

The following demand charges shall apply to each kw of maximum on-peak demand occurring during the billing period.

Summer Season	Charges
For each kw of maximum on-peak demand	$9.50 per kw
Winter Season	
For each kw of maximum on-peak demand up to 90% of Customer's Capacity Reservation	$4.97 per kw
For all kw of maximum on-peak demand in excess of 90% of Customer's Capacity Reservation	$2.42 per kw

*Asterisk indicates change.

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Decatur, Illinois

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ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 24 - PAGE 2

*3. Rates (continued)

(i) Summer Season is the first billing period having an ending meter reading date on or after June 15 and the three succeeding billing periods.

(ii) Winter Season is all billing periods not in the Summer Season.

(iii) The on-peak period is the 11 consecutive hours commencing at 10:00 a.m. and ending at 9:00 p.m. on Monday through Friday excluding New Year's Day, Good Friday, Memorial Day (May 30), July 4, Labor Day, Thanksgiving Day, Christmas Eve Day, and Christmas Day.

(iv) The off-peak period is all hours not in the on-peak period.

(b) Energy Charge

Customer shall be charged, for each billing period, $12.60 per kw of capacity reservation, plus 3.30¢ per kwh for all kwh used in the billing period in excess of 400 kwh per kw of capacity reservation.

(c) Time-of-Use Energy Credit

A credit of 1.00¢ per kwh shall apply to all kilowatthours used during the off-peak period in each month.

(1) The off-peak period for determination of an energy credit is the 13 consecutive hours commencing at 9:00 p.m. and ending at 10:00 a.m. on weekdays, all hours on the weekends, and all hours on New Year's Day, Good Friday, Memorial Day (May 30), July 4, Labor Day, Thanksgiving Day, Christmas Eve Day, and Christmas Day.

(2) The on-peak period is all other hours not in the off-peak period.

(d) Annual Load Factor Credit

Annually, at the conclusion of the December billing period, an Annual Load Factor Credit shall be calculated and credited to the customer's bill.

(1) The excess or unused energy for each month shall be calculated in the following manner:

Each month's kwh consumption less the quantity (400 kwh per kw times the capacity reservation in effect for the current month).

A positive result indicates excess energy for any month and a negative result indicates unused energy for any month.

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ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 24 - PAGE 3

*3. Rates (continued)

(2) The sum of all monthly excess energy equals the annual excess energy.

(3) The sum of all monthly unused energy equals the annual unused energy.

(4) If the annual excess energy is greater than or equal to the annual unused energy, the Annual Load Factor Credit shall be equal to 3.30 cents per kwh times the annual unused energy. If the annual excess energy is less than the annual unused energy, the Annual Load Factor Credit shall be equal to 3.30 cents per kwh times the annual excess energy.

(e) **Power Factor Adjustment**

The charges for each month shall be increased 0.4dc per kw of the maximum 15 minute demand measured in the month for each one percent or major fraction thereof by which Customer's measured power factor is less than 95% lagging. The measured power factor is the average power factor during the same 15 minute period in which the maximum demand is measured. No adjustment shall be made for power factors of 95% or higher.

(f) Fuel Cost Adjustment

The energy charges in subsections 3(b) and (c) are subject to the Fuel Cost Adjustment provided in Rider F. The Fuel Cost Adjustment shall be calculated and applied separately for each month only to the actual kwh used by Customer during the month.

*4. Determination of Capacity Reservation and Maximum On-Peak Demand

(a) The capacity reservation shall be equal to Customer's maximum on-peak demand occurring during the twelve consecutive billing periods ending with the current billing period, and occurring between June 15 and September 14, adjusted, if necessary, under the provisions of section 5 of Rider S. In no event shall the capacity reservation be less than 3,000 kw.

(b) The maximum on peak demand is the highest number of kw delivered during any 15-minute period of the on-peak period, as defined in subsection 3(a)(iii), in the billing period adjusted, if necessary under subsection 2(e), and/or section 4 of Rider S.

*5. Additional Conditions and Contract Provisions

(a) The primary term for the contract shall be determined as follows:

(1) Customers who are not taking service from Utility under the provisions of this service classification or Service Classification 21 shall contract for a primary term of five years.

(2) Customers taking service under the provisions of this service classification who desire to contract for additional capacity and those customers taking service under Service Classification 21 may contract for and take service for a primary term equal to the remainder of the primary term of the contract under which they are being served, but not less than one year; except that if Utility is required to install additional facilities to serve Customer's load, Customer and Utility shall enter into a new contract specifying the new capacity reservation required by Customer. The new contract shall be for a term of years determined as follows, but not less than the remainder of the primary term of the present contract:

(i) One year if no new or additional capacity reservation is required or if the new or added capacity reservation is less than 500 kw, or

*Asterisk indicates change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 24 — PAGE 4

*5. Additional Conditions and Contract Provisions (continued)

(ii) Three years if the new or added capacity reservation is equal to or greater than 500 kw but less than or equal to 1500 kw, or

(iii) Five years if the new or added capacity reservation is more than 1500 kw.

(b) Extension or termination of the term of any contract shall be determined as follows:

(1) The primary or extended term of any contract shall be automatically extended from year to year with the privilege of either party to terminate the contract at the end of the primary term or thereafter on not less than 12 months written notice.

(2) In the event Customer shall cease all operations and discontinue business at the location at which service is being rendered under such contract, Customer may, upon not less than 30 days written notice to Utility, cancel the contract then in effect at the beginning of any billing period commencing after the expiration of the primary term.

(c) An initial development period may be established by mutual agreement during which billings shall be based upon measured demands or capacity reservation not less than the greater of the following quantities:

(1) 2,000 kw, or

(2) one-third of the ultimate capacity reservation specified in the contract, or

(3) the highest measured demand since commencing service under the contract.

Such development period shall terminate when measured demands exceed 80% of the capacity reservation or at the first anniversary date of the contract, whichever event occurs first.

(d) Any existing or future contract required by this service classification to be entered into or entered into between Utility and Customer for electric service shall be amended from time to time to incorporate any revisions and changes in this service classification or any rider, standard term or condition, or rule, regulation or condition applying to electric service (including without limitation changes in rates, charges, and terms or conditions of service) when such revision, change or substitution shall be approved or permitted to go into effect under the Public Utilities Act or as otherwise provided by law. Nothing contained in any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract shall affect or be construed as affecting in any way the right of Utility unilaterally and without consent of Customer to take or initiate action, as permitted by applicable laws and regulations, to make revisions or changes in any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract.

NOTE: This service classification is subject to Utility's Standard Terms and Conditions in its Schedule of Rates for Electric Service.

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ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 30
Limited Firm Service

1. Availability

Any Customer located in territory served by Utility may take service under this service classification subject to the following conditions:

(a) that service is not available under this service classification if the utilization of service is of such character that service cannot be interrupted at any time by Utility without loss to Customer or damage to property or persons and without adversely affecting the public health, safety and welfare, and

(b) that the energy delivered is not resold or redistributed, and

(c) that service is not available under this service classification where Customer purchases electric energy from any other source than Utility, and

(d) that any Customer generating a portion of Customer's electric energy requirements shall not operate equipment in parallel with Utility's facilities unless prior written permission to do so has been obtained from Utility, and

(e) that service to Customer hereunder will not, in Utility's judgment, impair Utility's ability to serve the requirements of its firm customers and customers already taking service under this service classification, and

(f) that prior to the commencement of service, Customer shall enter into a written contract with Utility in accordance with this service classification.

2. Conditions of Service

(a) Service will be delivered to Customer from existing three phase electric lines having a nominal standard voltage of 34.5, 69 or 138 kv and possessing sufficient capability to supply the specified capacity. Utility shall have the right to select the supply lines from which service will be rendered to Customer.

(b) Customer shall provide and maintain all transformers and related facilities (including all switches, relays, communication circuits and other equipment necessary to establish and maintain control by Utility's Supply Dispatcher) necessary for handling and utilizing the energy delivered. Utility will furnish and maintain control facilities within its Supply Dispatcher's office.

(c) Utility will extend the three phase line necessary to provide service to Customer, provided the cost of such line extension does not exceed one and one-half times the annual revenue from Customer as estimated by Utility. Customer shall deposit with Utility a sum equal to any costs in excess of one and one-half times such estimated annual revenue. Refunds of such deposits will be made in accordance with Utility's Rules, Regulations and Conditions Applying to Electric Service.

(d) Utility will provide and maintain one three-phase delivery voltage.

(e) Customer shall make available, without charge to Utility, space required for Utility's lines and delivery facilities.

(f) Utility will provide and maintain one point of delivery and metering equipment therefor, except as otherwise provided in Utility's Rules, Regulations and Conditions Applying to Electric Service. Such metering equipment shall be located on the high voltage side of transformation in the event transformation shall be required by Customer unless Utility elects to install such metering equipment on the low voltage side of transformation, in which case both the demand and energy consumption shall be increased to compensate Utility for transformer losses.

(g) Utility will make interruptions in service from time to time as provided for herein. Whether or not notice is received by Customer in advance of the interruption, Utility shall have no liability to Customer, and Customer shall assume full responsibility, for any loss, damage, or claim (including but not limited to product loss and loss of profits) by reson of any interruption or restoration of service. Customer taking service receives a reduced charge in consideration of which Customer assumes all risk of loss and damage to Customer's property or business resulting from service interruptions.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 30 - PAGE 2

*3. Rates

(a) Limited Firm Capacity Charge

The monthly capacity charge per kw of reserve capacity shall be:

Kilowatts (kw) of Reserve Capacity	Charges
For the first 1,000 kw	$1,850.00
For all over 1,000 kw	$ 1.00 per kw

(b) Energy Charge

The energy charge for all limited firm energy delivered during the billing period shall be 3.26¢ per kwh.

(c) Time-of-Use Energy Credit

A credit of 1.00¢ per kwh shall apply to all kilowatthours used during the off-peak period in each month.

(i) The off-peak period for determination of an energy credit is the 13 consecutive hours commencing at 9:00 p.m. and ending at 10:00 a.m. on weekdays, all hours on the weekends and all hours on New Year's Day, Good Friday, Memorial Day (May 30), July 4, Labor Day, Thanksgiving Day, Christmas Eve Day and Christmas Day.

(ii) The on-peak period is all other hours not in the off-peak period.

(d) Power Factor Adjustment

The charges for each month shall be increased 0.48¢ per kw of the maximum 15 minute demand measured in the month for each one percent or major fraction thereof by which Customer's measured power factor is less than 95% lagging. The measured power factor is the average power factor during the same 15 minute period. No adjustment shall be made for power factors of 95% or higher.

(e) Fuel Cost Adjustment

The energy charges in subsection 3(b) are subject to the Fuel Cost Adjustment provided in Rider F.

(f) Firm Power

(1) Firm Power is that demand and energy for which Customer has contracted on a firm basis under an applicable service classification at the same point of delivery at which limited firm service is taken.

(2) Customer shall pay each month, in addition to the charges in Section 3, the charges specified under the service classification for which firm power was contracted.

(3) In the event Customer's maximum 15 minute demand established during a period of interruption exceeds the load limit specified by Utility plus the maximum amount of contracted firm power, Customer shall pay to Utility for each such occurrence (in addition to the rates provided herein) an amount equal to $9.69 per kw multiplied by the number of kw of such excess, and Customer's contracted firm power will be increased, without notice or other action, by the amount of such excess kw.

*Asterisk indicates change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 30 - PAGE 3

*4. Interruptions and Curtailments

(a) Interruptions of Service Other Than Intentional Interruptions or Curtailments

The following described interruptions of Customer's service shall not be deemed as "intentional interruption" as defined in subsection 4(b).

(1) Interruptions caused by act of God, public enemy, strikes, state, municipal or other governmental interference, windstorm, flood, fire, explosion or any matter or thing over which Utility has no control, whether in connection with the operations or property of either Customer or Utility.

(2) Interruptions caused by emergencies that cause Utility to order curtailment of service to firm customers in order to protect the general public and preserve the integrity of its system and the systems of neighboring utilities whose electric systems are interconnected with the electric system of Utility.

(b) Intentional Interruptions

Intentional interruptions shall be all interruptions of Customer's limited firm load made by Utility. Such interruptions may be made at any time at Utility's sole discretion, subject to the conditions of 4(c) hereof.

For any intentional interruption, Utility may specify a maximum limit for Customer's load and the periods in which such limits are effective.

(c) Limitations Upon Intentional Interruptions

The frequency of intentional interruptions will be no more than 60 per calendar year with such interruptions occurring on no more than 45 days during such year. The total hours of intentional interruptions will not exceed the equivalent of 200 hours of total interruption in any calendar year and no single intentional interruption will be longer than 12 consecutive hours.

(d) Notice of Interruption

Utility shall have the right to make any interruption without notice to Customer. Utility, however, will attempt to provide Customer with sufficient advance notice of intentional interruptions to permit an orderly shutdown of Customer's operation, but Utility shall have no obligation to give such advance notice or to assume any liability for failure to do so.

Notice of interruption may be given by telephone from Utility. Utility may agree to permit an interruption procedure to be carried out by Customer's personnel, provided all steps in such procedure are subject to control by Utility. In all other cases, Utility will accomplish the required interruption by a switching arrangement which is under its sole control. After any interruption of service, Customer shall not reconnect any load without approval from Utility.

*5. Additional Conditions and Contract Provisions

(a) The contract with Utility shall specify a reserve capacity of not less than 1,000 kw. Such contract may also specify an amount of firm power. The primary term for the contract shall be 5 years and thereafter from year to year.

(b) Customers taking service under the provisions of this service classification who desire to contract for additional reserved capacity and Customers taking service under Service Classification 21 or 24 hereunder may contract for and take service for a primary term equal to the remainder of the primary term of the contract under which they are being served, and thereafter from year to year, provided that, if additional three-phase line is installed pursuant to Section 2(c) hereof, the primary term of that contract or new contract shall be not less than 5 years.

(c) Customer's reserve capacity shall be increased, subject to the limitations in subsection 1(f), whenever the reserve capacity in effect shall have been exceeded during three 15 minute demand intervals, no two of which shall be selected in any one calendar day. In such case, Customer's

*Asterisk indicates change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

*5. Additional Conditions and Contract Provisions (continued)

reserve capacity shall be increased without notice to the average of such three measured demands and any existing contract shall be deemed to have been amended to include such increased reserve capacity. Such increased reserve capacity shall become effective with the billing period in which the third of such metered excess demands shall have occurred.

(d) An initial development period may be established by mutual agreement during which Customer's monthly demand for billing purposes shall be the maximum 15 minute demand established during the development period. The development period shall not exceed 12 months.

(e) During the off-peak period immediately following any notice of interruption or curtailment, Customer may exceed its reserve capacity by 100%, provided prior approval has been obtained from Utility. If such approval is granted, the demands established during such off-peak periods will not be used for billing purposes. Off-peak periods, for the purposes of this paragraph, shall be those consecutive hours commencing at 9:00 p.m. and ending at 10:00 a.m. on the following day.

(f) The primary or extended term of the contract shall be automatically extended from year to year with the privilege of either party to terminate the contract at the end of the primary term or thereafter on not less than 12 months written notice. Customer's reserve capacity may be reduced at the end of the primary term or during any extended term on written notice of not less than 12 months. However, in no event shall a reserve capacity be reduced more than once in any 12 month period.

(g) In the event of the permanent abandonment of the operations or any of Customer's facilities which utilize electric energy, Customer shall have the privilege of reducing the reserve capacity on twelve months prior written notice. The amount of Firm Power provided for herein shall also be proportionately reduced.

In the event Customer shall cease all operations and discontinue business at the location at which service is being rendered under such contract, Customer may, upon not less than 30 days written notice to Utility, cancel the contract then in effect at the beginning of any billing period commencing after the expiration of the then existing term.

(h) Customer shall not have the right to increase its limited firm reserve capacity except:

(1) to the extent that Utility has consented in writing to Customer's written request to increase reserve capacity within a specified time by the terms of the contract, or

(2) to the extent that such increased reserve capacity of Customer will not, in Utility's judgment impair Utility's ability to serve the requirements of its firm customers and its other customers taking service under this service classification.

(i) Any existing or future contract required by this service classification to be entered into or entered into between Utility and Customer for electric service shall be amended from time to time to incorporate any revisions and changes in this service classification or any rider, standard term or condition, or rule applying to electric service (including without limitation changes in rates, charges, and terms or conditions of service) when such revision, change or substitution shall be approved or permitted to go into effect under the Public Utilities Act or as otherwise provided by law. Nothing contained in any service classification, rider, standard term or condition, or rule applying to electric service, or in any existing or future contract, shall affect or be construed as affecting in any way the right of Utility unilaterally and without consent of Customer to take or initiate action, as permitted by applicable laws and regulations, to make revisions or changes in any service classification, rider, standard term or condition, or rule applying to electric service, or in any existing or future contract.

NOTE: This service classification is subject to Utility's Standard Terms and Conditions in its Schedule of Rates for Electric Service.

*Asterisk indicates change.

Issued January 13, 1983
Filed Pursuant to
Illinois Commerce Commission
Order in Docket 82-0152
Dated January 12, 1983.

Issued by Larry D. Haab
Vice President
Decatur, Illinois

Effective January 18, 1983

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 39
Outdoor Area Lighting

1. Availability

Any Customer located in territory served by Utility may take service under this service classification for lighting outdoor areas, where the period of lighting is limited from dusk to dawn, subject to the following conditions:

(a) that Customer is located adjacent to Utility lines from which such service can be rendered, and

(b) that Customer enters into a written contract with Utility for service.

2. Conditions of Service

(a) Utility shall furnish and install on Customer's premises an automatically controlled lighting fixture equipped with the type of lamp and lumen rating selected by Customer, and such fixture shall be attached to a standard type wood pole. Utility shall furnish all electric energy required to operate such fixture.

(b) Except for underground facilities installed and maintained by Customer under subsection 2(c), all lamps and additional facilities of Utility shall be operated and maintained by Utility.

(c) Underground facilities shall be provided only upon payment of the additional charges specified in subsection 3(b) and upon the following conditions:

(1) Direct-buried underground cables shall be used only in areas which will remain free of obstructions. Customer shall be responsible for any additional maintenance, repair or replacement costs if part or all of the area over such cables is subsequently paved or covered by other obstruction.

(2) In area determined by Utility not to be suitable for direct-buried underground cables, ducts or flexible conduit shall be installed by Customer, or at Customer's expense, by Utility. Customer shall retain ownership of such ducts or conduit and shall be responsible (when notified by Utility that such maintenance, repair or replacement is necessary) for the maintenance, repair or replacement of such ducts or conduit.

(3) Customer shall be responsible for and Utility shall not be liable for any damage to ground cover (such as grass, shrubs and trees) resulting from the installation, repair or replacement of underground facilities, and personal injury or property damage should any person other than Utility or its employees dig into underground facilities.

ILLINOIS POWER COMPANY
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SERVICE CLASSIFICATION 39 - PAGE 2

*3. Rates

(a) Lamp Charges

If the lighting fixture can be installed on an existing distribution type wood pole and service can be supplied from an existing overhead secondary circuit on the pole, the monthly charges applicable to such installation shall be as follows:

Type of Lamp	Lumen Rating	Wattage Rating	Charges Per Month
Area Lighting			
Incandescent	2,500)	Not available to new installations after January 18, 1983	$ 5.80
"	4,000)	Not available to	6.40
"	6,000)	new customers after	7.25
"	10,000)	September 20, 1969	9.25
Mercury Vapor	6,400	175	4.85
"	9,400	250	5.90
"	16,000	400	8.50
"	45,200	1,000	16.65
Sodium Vapor	8,500	100	6.50
"	15,000	150	7.00
"	22,000	250	9.35
"	45,000	400	11.65
Directional Lighting			
Mercury Vapor	16,000	400	10.40
"	45,200	1,000	17.90
Sodium Vapor	22,000	250	13.35
"	45,000	400	16.00

(b) Additional Charges

If additional facilities or fixtures other than Utility's standard type of rearrangement of existing facilities shall be required to serve Customer, Utility shall install, operate and maintain such facilities for an additional monthly charge of 1.5% of the estimated reproduction cost new of such additional facilities at the time of rental or rearrangement as may be required. These charges shall be in addition to the lamp charges.

4. Contract Provisions

The contract shall specify a term of years determined as follows:

(a) One year, if additional facilities are not required, or

(b) Three years, where additional facilities or rearrangement are required.

The primary or extended term of any contract shall be automatically extended from year to year with the privilege of either party to terminate the contract at the end of the primary term or at any time during any extended term on not less than 10 days written notice.

*Asterisk indicates change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 39 - PAGE 3

5. Additional Conditions and Contract Provisions

Any existing or future contract required by this service classification to be entered into or entered into between Utility and Customer for electric service shall be amended from time to time to incorporate any revisions and changes in this service classification or any rider, standard term or condition, or rule, regulation or condition applying to electric service (including without limitation changes in rates, charges, and terms or conditions of service) when such revision, change or substitution shall be approved or permitted to go into effect under the Public Utilities Act or as otherwise provided by law. Nothing contained in any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract shall affect or be construed as affecting in any way the right of Utility unilaterally and without consent of Customer to take or initiate action, as permitted by applicable laws and regulations, to make revisions or changes in any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract.

NOTE: This service classification is subject to Utility's Standard Terms and Conditions in its Schedule of Rates for Electric Service.

Issued July 2, 1981

Effective July 3, 1981

Issued by Larry D. Haab
Vice President
Decatur, Illinois

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 41
Municipal Service

1. Availability

This service classification is available to any city, village or town (hereinafter called "Municipality"), in which Utility is rendering electric service under a franchise ordinance having a term of not less than 20 years, granting Utility the privilege of occupying the streets, alleys and other public places, for the purpose of transmission, sale and distribution of electric service. This schedule is not applicable to resale, standby or auxiliary service.

2. Conditions of Service

(a) Service will be furnished at standard primary or secondary distribution voltage at Utility's option.

(b) Utility will combine meter readings for all service rendered to the Municipality under this Service Classification.

*3. Rates

(a) Facilities Charge $6.50 per month for each point of delivery

(b) Energy Charge

The following charges shall apply to all usage for bills issued during the following seasons:

Summer Season (1) Kilowatt hours (kwh) Used in Any One Month	Charges	Winter Season (2) Kilowatt hours (kwh) Used in Any One Month	Charges
For all kwh	5.28¢ per kwh	For the first 1300 kwh times the total number of delivery points	4.78¢ per kwh
		For all kwh in excess of 1300 kwh times the total number of delivery points	3.20¢ per kwh

(1) Summer Season is the billing periods of June, July, August and September.

(2) Winter Season is all billing periods not in the summer season.

(c) Fuel Cost Adjustment

The energy charges in subsection 3(b) are subject to the Fuel Cost Adjustment provided in Rider F.

(d) Contract Term Discount

The charges in subsection 3(b), reduced by 1.70¢ per kwh, shall be subject to a discount of 10% if Customer has in effect a contract ordinance with an effective date prior to July 3, 1981 and a term of 10 years or more.

4. Contract Provisions

Service will not be provided by Utility unless a contract ordinance has been adopted by Municipality authorizing the purchase of service for a term of not less than 10 years or the remaining term of any existing electric franchise ordinance.

*Asterisk indicates change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 41 - PAGE 2

5. Additional Conditions and Contract Provisions

Any existing or future contract required by this service classification to be entered into or entered into between Utility and Customer for electric service shall be amended from time to time to incorporate any revisions and changes in this service classification or any rider, standard term or condition, or rule, regulation or condition applying to electric service (including without limitation changes in rates, charges, and terms or conditions of service) when such revision, change or substitution shall be approved or permitted to go into effect under the Public Utilities Act or as otherwise provided by law. Nothing contained in any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract shall affect or be construed as affecting in any way the right of Utility unilaterally and without consent of Customer to take or initiate action, as permitted by applicable laws and regulations, to make revisions or changes in any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract.

NOTE: This service classification is subject to Utility's Standard Terms and Conditions in its Schedule of Rates for Electric Service.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 42
Miscellaneous Municipal Service

1. Availability

This service classification is available to any city, village, or town and to any park or sanitary district situated within or adjacent to Utility's distribution system in any such city, village or town (hereinafter called "Municipality") in which Utility is rendering electric service under an ordinance granting Utility the privilege of occupying the streets, alleys, and other public places for the purpose of transmission, distribution, and sale of electric service. This schedule is not applicable to resale, standby, or auxiliary service.

2. Conditions of Service

(a) Service will be furnished at standard primary or secondary distribution voltage at Utility's option.

(b) Utility will combine meter readings for all service rendered to the Municipality under this service classification.

*3. Rates

(a) Facilities Charge $10.00 per month per delivery point

(b) Energy Charge

The following charges shall apply to all usage for bills issued during the following seasons:

Summer Season (1)		Winter Season (2)	
Kilowatt hours (kwh) Used in Any One Month	Charges	Kilowatt hours (kwh) Used in Any One Month	Charges
For all kwh	7.07¢ per kwh	For the first 1300 kwh times the total number of delivery points	5.20¢ per kwh
		For all kwh in excess of 1300 kwh times the total number of delivery points	2.20¢ per kwh

(1) Summer Season is the billing periods of June, July, August and September.

(2) Winter Season is all billing periods not in the summer season.

(c) Fuel Cost Adjustment

The energy charges in subsection 3(b) are subject to the Fuel Cost Adjustment provided in Rider F.

4. Contract Provisions

Service will not be provided by Utility unless a contract ordinance has been adopted by Municipality authorizing the purchase of service for a term not less than 5 years.

*Asterisk indicates change.

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Vice President
Decatur, Illinois

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 42 - PAGE 2

5. Additional Conditions and Contract Provisions

Any existing or future contract required by this service classification to be entered into or entered into between Utility and Customer for electric service shall be amended from time to time to incorporate any revisions and changes in this service classification or any rider, standard term or condition, or rule, regulation or condition applying to electric service (including without limitation changes in rates, charges, and terms or conditions of service) when such revision, change or substitution shall be approved or permitted to go into effect under the Public Utilities Act or as otherwise provided by law. Nothing contained in any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract shall affect or be construed as affecting in any way the right of Utility unilaterally and without consent of Customer to take or initiate action, as permitted by applicable laws and regulations, to make revisions or changes in any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract.

NOTE: This service classification is subject to Utility's Standard Terms and Conditions in its Schedule of Rates for Electric Service.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 45
Municipal Street Lighting Service

*1. Availability

This service classification is available to any city, village, or town, or to any park district situated within or adjacent to any city, village or town (hereafter called "Municipality"), in which Utility is rendering electric service under an ordinance granting Utility the privilege of occupying the streets, alleys, and other public places in said municipality for the purpose of transmission, distribution, and sale of electric service, and under the specific limitations herein provided, to other municipalities (i.e., cities, villages and towns in which Utility does not have a franchise), and citizen groups.

The rates provided without contract term or quantity discounts shall be available to Municipalities in which Utility has no currently effective franchise or with citizen groups contracting to take street lighting service from Utility for not less than a 5 year period in areas where Utility owns and operates adequate electric service facilities.

Incandescent lamps shall not be available for new installations.

*2. Class of Service

Utility will furnish the classes of service described below, each at the corresponding charges per lamp per month, including maintenance, electric energy requirements, and replacements of lamps and other glassware as required on systems owned and operated by Utility, but only including electric energy requirements and lamp replacements on systems owned and operated by Municipality.

Class A - Incandescent lamps on standard overhead wood pole construction, owned and operated by Utility. (See availability)

Class B - Incandescent lamps on standard overhead concrete pole construction or on existing metal pole construction, owned and operated by Utility. (See availability)

Class C - Either incandescent, mercury vapor or sodium vapor lamps owned and operated by Municipality. (See availability)

Class D - Either mercury vapor or sodium vapor lamps on standard overhead wood pole construction, owned and operated by Utility.

Class E - Either mercury vapor or sodium vapor lamps on standard overhead concrete pole construction or on existing metal pole construction, owned and operated by Utility.

*3. Rates

(a) Charges per Lamp per Month.

The following rates are based on 4,000 hours per year burning schedule including all hours of darkness:

Incandescent (see Availability) Size	Class A	Class B	Class C	Class D	Class E
1,000 Lumen	$3.95	$ -	$1.50	$ -	$ -
2,500 Lumen	4.70	7.90	2.35	-	-
4,000 Lumen	6.10	8.95	3.45	-	-
6,000 Lumen	8.15	11.85	4.60	-	-
10,000 Lumen	11.00	15.10	-	-	-

*Asterisk indicates change.

Issued January 13, 1983
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Decatur, Illinois

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ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 45 - PAGE 2

*3. Rates (continued)

Mercury Vapor Size		Class A	Class B	Class C	Class D	Class E
7,200 Lumen,	175 Watts	-	-	$ 2.70	$ 8.70	$13.90
11,000 Lumen,	250 Watts	-	-	3.60	9.70	15.20
17,000 Lumen,	400 Watts	-	-	5.60	12.45	15.95
30,000 Lumen,	700 Watts	-	-	8.90	18.10	25.20
46,000 Lumen,	1,000 Watts	-	-	10.80	20.05	29.10

Sodium Vapor Size		Class A	Class B	Class C	Class D	Class E
8,700 Lumen,	100 Watts	-	-	$ 3.20	$10.65	$16.80
15,000 Lumen,	150 Watts	-	-	5.15	11.40	17.00
23,000 Lumen,	250 Watts	-	-	7.40	13.60	20.00
46,500 Lumen,	400 Watts	-	-	10.80	17.45	23.75

(b) Contract Term Discount

The charges in subsection 3(a) shall be subject to a discount of 10% if Customer has in effect a contract ordinance with an effective date prior to July 3, 1981 and a term of 10 years or more.

(c) Quantity Discounts

The charges in subsections 3(a) and 3(b) shall be subject to additional discounts, as follows:

For the first $ 48.46 of the foregoing charges per month, no discount.
For the next $145.38 of the foregoing charges per month, 3% discount.
For the next $678.44 of the foregoing charges per month, 5% discount.
For all over $872.28 of the foregoing charges per month, 10% discount

(d) Additional Charges

Where Utility installs, operates, and maintains facilities other than those facilities used in standard overhead street lighting installation, Customers shall pay a monthly charge equal to 1.5% of the reproduction cost new of such additional facilities. These additional charges shall be in addition to those charges provided for above.

4. Contract Provisions

Utility shall not be required to provide or install street lighting systems and facilities or furnish service under this service classification unless a contract ordinance has been adopted by Municipality authorizing the purchase of service for a term of not less than 5 years from the date of such installation.

5. Premature Replacement of Mercury Vapor Lamps

In the event Customer requests Utility to replace a mercury vapor lamp with a sodium vapor lamp during the primary term of any contract in existence as of November 28, 1977, the Customer must pay Utility for the cost of labor (including transportation and overheads) for replacing such lamp.

*Asterisk indicates change.

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Decatur, Illinois

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ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

SERVICE CLASSIFICATION 45 - PAGE 3

6. Additional Conditions and Contract Provisions

Any existing or future contract required by this service classification to be entered into or entered into between Utility and Customer for electric service shall be amended from time to time to incorporate any revisions and changes in this service classification or any rider, standard term or condition, or rule, regulation or condition applying to electric service (including without limitation changes in rates, charges, and terms or conditions of service) when such revision, change or substitution shall be approved or permitted to go into effect under the Public Utilities Act or as otherwise provided by law. Nothing contained in any service classification, rider, standard term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract shall affect or be construed as affecting in any way the right of Utility unilaterally and without consent of Customer to take or initiate action, as permitted by applicable laws and regulations, to make revisions or changes in any service classification, rider, standard and term or condition, or rule, regulation or condition applying to electric service, or in any existing or future contract.

NOTE: This service classification is subject to Utility's Standard Terms and Conditions in its Schedule of Rates for Electric Service.

Issued July 2, 1981

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Issued by Larry D. Haab
Vice President
Decatur, Illinois

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

RIDER A
Municipal Tax Additions

Pursuant to the provisions of Section 36 of the Public Utilities Act, as amended, authorizing certain additional charges for services rendered in municipalities imposing the tax authorized by Section 8-11-2 of the Illinois Municipal Code, Utility will add the percentage shown below opposite the names of such municipalities to all billings (which shall include the percentage addition for State of Illinois Revenues Taxes shown on Rider AA) for electricity furnished for use or consumption and not for resale, and for all services rendered in connection therewith, within the corporate limits of such municipalities (except items of such billings resulting from transactions not subject to such tax). The effective date for such additions will coincide with the date upon which the gross receipts from such billings become subject to tax. The amount of the additions will be separately designated on each Customer's bill as "Municipal Tax" or by a similar legend.

Name of Municipality	Municipal Tax Rates	Percentage Addition to Billings	Effective Date
Arlington	5.00%	5.15%	October 1, 1967
*Ava	3.00%	3.09%	December 6, 1983
Belleville	1.00%	1.03%	November 1, 1983
Bloomington	2.00%	2.06%	May 1, 1979
Brooklyn	5.00%	5.15%	August 21, 1961
Buffalo	5.00%	5.15%	September 25, 1970
Cahokia	5.00%	5.15%	November 1, 1969
Cambridge	2.30%	2.37%	November 1, 1962
Centreville	5.00%	5.15%	September 1, 1969
Champaign	2.75%	2.83%	November 1, 1964
Cherry	5.00%	5.15%	January 4, 1961
Colfax	5.00%	5.15%	February 1, 1979
Columbia	3.00%	3.09%	September 1, 1981
Dawson	5.00%	5.15%	February 6, 1967
De Pue	2.00%	2.06%	September 16, 1978
East Carondelet	3.00%	3.09%	January 1, 1956
East Galesburg	3.00%	3.09%	August 22, 1971
East St. Louis	5.00%	5.15%	February 15, 1968
Equality	5.00%	5.15%	June 1, 1974
Keithsburg	5.00%	5.15%	March 15, 1964
LaSalle	2.00%	2.06%	July 1, 1982
Madison	5.00%	5.15%	July 1, 1981
Marseilles	3.00%	3.09%	October 1, 1981
Maryville	3.00%	3.09%	June 1, 1966
Mt. Olive	5.00%	5.15%	October 1, 1957
National City	5.00%	5.15%	August 1, 1979
Newark	5.00%	5.15%	November 1, 1966
New Athens	2.76%	2.84%	December 31, 1981
Normal	5.00%	5.15%	July 1, 1965
Pontoon Beach	5.00%	5.15%	December 18, 1970
Prairie du Rocher	3.00%	3.09%	January 1, 1976
Ridgway	5.00%	5.15%	December 1, 1971
Shawneetown	5.00%	5.15%	September 1, 1967
South Roxana	5.00%	5.15%	October 1, 1976
Steeleville	3.00%	3.09%	October 1, 1963
Urbana	5.00%	5.15%	October 1, 1974
Valmeyer	4.00%	4.12%	June 4, 1982
Venice	3.00%	3.09%	July 1, 1979

*Asterisk indicates change.

Issued December 5, 1983

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Issued by Larry D. Haab
Senior Vice President
Decatur, Illinois

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

RIDER AA
State of Illinois Revenue Taxes

Pursuant to the provisions of Section 36 of the Public Utilities Act, as amended, authorizing certain additional charges for services rendered in the State of Illinois on account of the addition of State Public Utility Tax and the Illinois Commerce Commission Gross Revenue Tax, Utility will add such taxes to all billings for electricity furnished for use or consumption and not for resale, and for all services rendered in connection therewith (except items of such billing resulting from transactions not subject to such tax). The percentage additions to all billings subject to the State Revenue Taxes and the date on which such billings will become effective are as follows:

State Tax	Percentage Addition	Effective Date
State Public Utility Tax	5.00%	*January 3, 1983
Illinois Commerce Commission Gross Revenue Tax	0.08%	*January 3, 1983
Total State Revenue Taxes	5.08%	

*Asterisk indicates change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

RIDER D
Temporary Service

1. Availability

Service is available for temporary or short-term electric service but is not available for resale, standby or auxiliary service.

2. Conditions of Service

(a) Customer shall pay in advance the estimated charges for service under the applicable service classification, plus the non-salvable cost, as estimated by Utility, of installing and removing all additional facilities necessary to render service.

(b) Customer's contract capacity under the applicable service classification shall not be less than minimum transformer capacity required to s ve Customer's load.

(c) If the period of service shall exceed 6 weeks, the advance payment in subsection 2(a) will be limited to the estimated charges for the first 6 weeks' service, provided however, that Customer shall first have established credit to Utility's satisfaction. This shall be contingent upon payment in full of the first and each succeeding monthly bill for service within 10 days from the date thereof.

(d) After service is discontinued, Utility will refund the balance, if any, of funds deposited by Customer remaining after deducting the estimated non-salvable costs of providing service and any balance due from Customer for service rendered.

(e) After discontinuance of service, Utility may at its discretion remove the additional facilities installed for service. However, if Utility elects to leave such facilities installed and service is again requested at the same location, such service will be made available only after payment by Customer of one of the following amounts:

(1) the monthly charge in effect when service was discontinued, prorated over the period from the date service was discontinued through the date service is again made available, or

(2) the cost of installing and removing all necessary additional facilities as provided in subsection 2(a).

3. Rates

Customer will be served under the provisions of Utility's Service Classifications 10, 11 or 21, whichever is applicable (except that the provisions thereof related to term of contract shall not apply), subject to the above terms.

Issued July 2, 1981

Effective July 3, 1981

Issued by Larry D. Haab
Vice President
Decatur, Illinois

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

RIDER F
Fuel Cost Adjustment

* Applicable to Service Classifications 1, 2, 3, 10, 11, 13, 21, 24, 30, 41, and 42, and all large power contracts permitted to become effective by the Illinois Commerce Commission.

This rider is applicable to kilowatthours (kwh's) of energy supplied to Customers served by Utility under the above designated service classifications and individual contracts on file with the Illinois Commerce Commission (Commission) where the charge for such energy is subject to adjustment for increases and decreases in the cost of fuel.

Costs passed through the fuel adjustment clause represent either actual historical costs or estimates of historical costs (when actual is not available at time of computation), subject to adjustment as actual costs become available. The fuel costs used in calculating fuel adjustment charge are the total of allowable fuel and fuel related costs as identified herein.

The charges for all kwh's of energy supplied to designated customers shall be increased or decreased by a fuel adjustment charge or credit determined as follows:

$$FAC = \left[\left(\frac{CF + CPP - CNS}{S}\right) - BFC + R_a + R_o\right] \times GT$$

where:

FAC = Fuel Adjustment Charge or Credit per kwh. The amount in cents per kwh, rounded to the nearest .001c, to be charged for each kwh billed during any monthly billing period.

The FAC is subject to adjustment to minimize accumulated over/under recoveries of fuel costs by application of the automatic reconciliation factor (R_a) and the ordered reconciliation factor (R_o) as defined herein.

CF = Allowable Cost of Fuel associated with Utility owned generating plants. Fuel cost includes the cost of all fossil and nuclear fuel consumed in Utility's owned plants and/or in plants owned by wholly-owned subsidiaries of Utility and/or the Utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants during the determination period.

CPP = Allowable energy Cost associated with Purchased Power. Purchased power includes emergency, contract, and economy purchases. Only the energy related portion of the charges for power purchased during the determination period is included. All other associated charges are specifically excluded. Non-monetary exchanges of power are not included.

CNS = Fuel Costs associated with sales Not Subject to the Fuel Adjustment Clause. Non-jurisdictional sales include sales for resale, interdepartmental sales, energy furnished without charge, and other sales not subject to the fuel adjustment clause.

Such fuel costs are calculated on the basis of the average fuel costs during the determination period except in the case of fuel costs associated with interchange power sales (emergency, contract and economy power sales to other electric utilities) which are the amounts recovered with respect to fuel in such sales, ordinarily the incremental cost of such fuel.

S = Sales. Kwh's billed to ultimate consumers, during the determination period, subject to the fuel adjustment clause.

BFC = Base Fuel Cost. The base fuel cost is the fuel cost included in the energy charges of Utility's service classifications. This base cost is equal to 1.750 cents per kilowatthour.

R_a = Automatic Reconciliation factor. The automatic reconciliation factor (R_a) is triggered when the accumulated balance of the over/under r coveries of allowable costs at the end of the last month of the determination period exceeds ten percent of (CF + CPP - CNS) for the determination period.

*Asterisk indicates change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

RIDER F - Page 2
Fuel Cost Adjustment

If so triggered, the automatic reconciliation factor (R_a) is positive or negative (depending on whether there has been an accumulated under or over recovery) and shall be equal to ten percent of

$$\frac{CF + CPP - CNS}{S}$$

for the determination period related to the billing period in which the factor is to be applied.

R_o = Ordered Reconciliation factor. The FAC is subject to an ordered reconciliation factor (R_o) as may be required by the Commission.

*GT = Gross Receipts Tax factor. The gross receipts revenue tax factor is calculated in accordance with the following formula:

$$GT = \frac{100}{(100 - t)}$$

where t is the revenue tax rate embodied in the Utility's service classifications. This tax rate (t) is equal to -0.08 percent.

The billing period is the period beginning with the first billing cycle of the second month following the determination period and ending with the last billing cycle thereof.

The determination period is a period of two consecutive months ending at least one month before the first billing cycle of the billing period.

The allowable fuel and fuel related costs (CF) will include the direct cost of fuel delivered at Utility's generating plants. The direct fossil fuel costs are limited to costs entered into fuel expense Accounts #501 and #547 which have been cleared upon consumption from Fuel Stock Account #151, or in the case of gas fuel the amount which is charged directly to Accounts #501 and #547. Costs cleared from Fuel Stock Accounts #152 and #153 are specifically excluded.

The cost of nuclear fuel will be that as expensed in Account #518, except that handling costs for nuclear fuel assemblies, spent fuel disposal costs, or any expense for fossil fuel which has already been included in the costs of fossil fuel, are specifically excluded.

The interpretation and application of this rider will be in accordance with all provisions set forth in General Order 211 as ordered by the Commission.

*Asterisk indicates change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

RIDER S
Supplemental Interruptible Electric Service

*1. Availability

Service is available to any customer located in territory served by Utility subject to the following conditions:

(a) that Customer takes firm service under Utility's Service Classification 21 - Large Power Service with a contract capacity of at least 1000 kw or Service Classification 24 - Annual Load Factor Large Power Service, and

(b) that service is not available under this Rider if the utilization of service is of such character that service cannot be interrupted or curtailed at any time by utility without loss to customer or damage to property or persons and without adversely affecting the public health, safety or welfare, and

(c) that Utility may limit service under this rider to 50 customers, and

(d) that prior to the commencement of service Customer shall enter into a written agreement with Utility and specify a Supplemental Interruptible Capacity.

2. Conditions of Service

(a) Supplemental Interruptible Electric Service is interruptible electric service provided to Customer in addition to service provided under a firm service classification. The provision of Supplemental Interruptible Electric Service is subject to unlimited interruptions and curtailments by Utility during the on-peak periods of both summer and winter seasons. The capacity required to provide Supplemental Interruptible Electric Service shall be referred to as Supplemental Interruptible Capacity. Whether or not notice is received by Customer in advance of any interruption or curtailment, Utility shall have no liability to Customer, and Customer shall assume full responsibility for any loss, damage or claim (including but not limited to product loss and loss of profits) by reason of any interruption, curtailment or restoration of service.

(b) Supplemental energy shall be defined for billing purposes as all energy used by Customer during the on-peak period defined in Customer's firm service classification in excess of Customer's contract capacity or capacity reservation.

(c) Supplemental Interruptible Electric Service shall not be available during periods in which service to Utility's customers taking service under firm or limited firm service classification is curtailed.

(d) Firm Power is that demand and energy for which Customer has contracted for on a firm basis under an applicable service classification at the same point of delivery as Supplemental Interruptible Electric Service. Customer shall pay each month, in addition to the charges in subsection 3(a) and 3(b), the charges specified under the service classification for which firm power was contracted.

*3. Rates

(a) Supplemental Interruptible Electric Service

(1) Demand Charge - Customer shall pay $.10 per billing period for each kw of Supplemental Interruptible Capacity during all billing periods.

In the event Customer's maximum 15 minute demand during a period of interruption exceeds the load limit specified by Utility plus the amount of firm power for which Customer has contracted, Customer shall pay to Utility for each such occurrence (in addition to the charges provided in the customer's applicable service classification) an additional amount equal to the demand charge in the applicable service classification multiplied by the number of kw of such excess, and the amount of firm power for which Customer has contracted will be increased, without notice or other action, by the amount of such excess kw.

*Asterisk indicates change.

Issued January 13, 1983
Filed Pursuant to
Illinois Commerce Commission
Order in Docket 82-0152
Dated January 12, 1983.

Issued by Larry D. Haab
Vice President
Decatur, Illinois

Effective January 18, 1983

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

RIDER S - PAGE 2

*3. Rates (continued)

(2) Energy Charge

The energy charge for Supplemental Interruptible Electric Service shall be determined as follows:

(i) During periods in which Utility anticipates operating generating units having a heat rate greater than 15,000 Btu's per kwh or purchasing energy under the emergency provisions of its interchange agreements, the charge shall be 6.10¢ per kwh.

(ii) During all other periods, the charge shall be determined in accordance with the provisions of subsection 3(b) of the service classification under which Customer takes firm service.

(b) Fuel Cost Adjustment

The schedule of charges set forth above is subject to the Fuel Cost Adjustment provided in Rider F. The Fuel Cost Adjustment shall be calculated and applied separately for each month only to the actual kwh used by Customer during the month.

*4. Adjustment of Maximum On-Peak Demands For Billing Purposes

In the event that Customer's maximum on-peak demand exceeds the amount of firm power for which Customer has contracted, the demand for billing under Customer's applicable service classification shall be Customer's maximum on-peak demand less the Supplemental Interruptible Capacity to the extent not curtailed but not less than the amount of firm power demand contracted for under Customer's applicable service classification.

*5. Adjustment of Firm Power Contract Capacity or Capacity Reservation

The amount of firm power determined according to the provisions of customer's applicable service classification shall be adjusted to the greater of the following:

(a) Customer's maximum on-peak demand from June 15 through September 14 less the amount of Supplemental Interruptible Capacity allowed by Utility during a period of curtailment.

(b) Customer's maximum on-peak demand from June 15 through September 14 less the customer's Supplemental Interruptible Capacity during a period with no curtailment.

*6. Interruptions and Curtailments

(a) Utility shall have the right to make any interruption or curtailment without notice to Customer. Utility, however, will attempt to provide Customer with two hours notice of any interruption or curtailment, but Utility shall have no obligation to give such advance notice or to assume any liability for failure to do so.

(b) Notice of interruption or curtailment may be given by telephone from Utility. Customer shall designate a representative to Utility to whom notice of an interruption or curtailment can be provided.

(c) Utility may agree to permit an interruption procedure to be carried out by Customer's personnel, provided all steps in such procedure are subject to control by Utility. Customer shall provide, at his expense, a direct line telephone connection between Utility's Supply Dispatch office and Customer's dispatch office.

(d) After any interruption or curtailment of service, Customer shall not reconnect any load to Utility's system without approval from Utility.

*Asterisk indicates change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

RIDER S - PAGE 3

7. Additional Conditions and Contract Provisions

(a) Customers taking supplemental interruptible service under this Rider shall contract for and take service for a primary term of twelve (12) months. The primary term or extended term of any contract shall be automatically extended from year to year with the privilege of either party to terminate the contract at the end of the primary term or during any extended term on not less than 30 days written notice.

(b) Utility may agree to increase customer's firm power for which customer has contracted at any time provided customer has given utility not less than twenty-four (24) hours notice before such increase shall become effective.

Issued January 13, 1983
Filed Pursuant to
Illinois Commerce Commission
Order in Docket 82-0152
Dated January 12, 1983.

Issued by Larry D. Haab
Vice President
Decatur, Illinois

Effective January 18, 1983

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

RIDER T
Municipal Taxes on Consumers
of Utility Services

Whenever, after April 1, 1981, the Company incurs an obligation to collect a municipal tax or other charge (or an increase therein) on consumers, measured by sales or revenues from the use or consumption of electricity other than a municipal tax authorized by Section 8-11-2 of the Illinois Municipal Code charges for which are made under Rider A, the Company will collect from its customers within the corporate limits of the municipality, in addition to amounts authorized by other provisions of the applicable rates and riders, an amount equal to such tax or other charge, or increase therein.

Listed below are municipalities which require the payment of any such tax or other charge by consumers of electric service and the amounts added to customers' bills in connection therewith.

Name of Municipality	Percentage Addition to Billing	Effective Date	Ordinance Number
East St. Louis	*0.00%	April 1, 1982	81-10006
National City	*0.00%	July 1, 1981	562

*Asterisk indicates change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

RIDER P

Parallel Generation Service
(Filed in compliance with Section 8.1 of General Order No. 214)

1. Availability

Any Customer located in territory served by Utility may take service under this rider subject to the following conditions:

(a) that Customer enter into a written contract with Utility, and

(b) that Customer is a qualifying facility as defined in Subpart B, Part 292, Subchapter K, Chapter I, Title 18, of the Code of Federal Regulations.

2. Conditions of Service

(a) Phase and voltage of Customer's interconnected generation shall be identical to that provided by Utility.

(b) Customer and Utility agree to indemnify each other for any tortious damages to any person or property resulting from any connection with work or services to be performed hereunder.

(c) Customer shall pay the cost of interconnection including initial and future transmission, distribution, metering, service and other facilities costs necessary to permit interconnected operations with the utility.

3. Rates

The following charges and credits shall apply:

(a) Facilities Charge - Customer shall pay for interconnection costs in accordance with paragraph 4(b) herein.

*(b) Energy Credit

(1) Standard Energy Rate

The following energy credits shall apply to all energy delivered by Customer into Utility's system at the following voltages:

Summer Season (i)

Kilowatt hours (kwh) Delivered in Any One Month	Credit 138 kv, 69 kv & 34.5 kv	12.47 kv and 4.16 kv	2.4 kv and below
All kwh delivered during on-peak periods (iii)	2.80c per kwh	2.89c per kwh	3.04c per kwh
All kwh delivered during off-peak periods (iii)	1.65c per kwh	1.69c per kwh	1.75c per kwh

Winter Season (ii)

Kilowatt hours (kwh) Delivered in Any One Month	138 kv, 69 kv & 34.5 kv	12.47 kv and 4.16 kv	2.4 kv and below
All kwh delivered during on-peak periods (iii)	2.93c per kwh	3.01c per Kwh	3.14c per kwh
All kwh delivered during off-peak periods (iii)	1.91c per kwh	1.95c per kwh	2.01c per kwh

(i) Summer Season is the first billing period having an ending meter reading date on or after June 15 and the three succeeding monthly billing periods.

(ii) Winter Season is all billing periods not in the summer season.

*Asterisk Indicates Change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

RIDER P - Page 2

3. Rates (continued)

(iii) The on-peak and off-peak periods will be the same as those defined in the service classification under which Customer is served. In the event Customer is not served under one of Utility's standard time-of-day service classifications, the following shall be the on-peak and off-peak periods:

(a) The on-peak period is the 11 consecutive hours commencing at 10:00 a.m. and ending at 9:00 p.m., on Monday through Friday, excluding New Years Day, Good Friday, Memorial Day (May 30), July 4, Labor Day, Thanksgiving Day, Christmas Eve Day and Christmas Day.

(b) The off-peak period is all hours not in the on-peak period.

(2) Optional Non Time-of-Day Energy Rate

In the event that Customer desires service without time-of-day provisions, Customer may elect to receive energy credits for all energy delivered by Customer into Utility's system at the following voltages:

Summer Season (i)

Kilowatt hours (kwh) Delivered in Any One Month	Credit 138 kv, 69 kv & 34.5 kv	12.47 kv and 4.16 kv	2.4 kv and below
For all kwh	2.02¢ per kwh	2.07¢ per kwh	2.16¢ per kwh

Winter Season (i)

Kilowatt hours (kwh) Delivered in Any One Month			
For all kwh	2.23¢ per kwh	2.28¢ per kwh	2.37¢ per kwh

(i) Summer Season is the first billing period having an ending meter reading date on or after June 15 and the three succeeding monthly billing periods.

(ii) Winter Season is all billing periods not in the summer season.

(c) Utility shall prepare a statement monthly of the charges and credits determined by a and b above. Customer shall pay Utility for any charges in accordance with the Standard Terms and Conditions and Rules and Regulations and Utility shall pay Customer for any credits within 30 days of the meter reading date.

In lieu of the Standard Energy Rate or the Optional Non Time-of-Day Rate shown above, the Customer may negotiate a rate in accordance with Section 8 "Contractual Arrangements Between Qualifying Facilities and Utilities" of Illinois Commerce Commission General Order No. 214.

4. Additional Conditions and Contract Provisions

(a) Customer shall enter into a written contract with Utility for such service for a period of not less than one year. The primary term shall be automatically extended from year to year with the privilege of either party to terminate the contract at the end of the primary term or at any time during any extended term on not less than 30 days prior written notice.

(b) Customer shall pay in advance the estimated charges for the Utility's cost of installing and removing all facilities necessary to render service under this rider. The salvable cost of all such equipment may, at Customer's option, be rented in accordance with Utility's Rules, Regulations and Conditions Applying to Electric Service.

(c) Utility shall have free access to Customer interconnection at all times to monitor operation of the Customer's equipment, Utility-supplied service equipment connected to such system, or to disconnect for good cause, without prior notice to Customer, Customer's equipment from Utility distribution system.

*Asterisk Indicates Change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

4. Additional Conditions and Contract Provisions (continued)

(d) Utility shall have the right to inspect and approve all plans for parallel generation systems and the actual systems prior to initial operation or subsequent operation following modifications.

(e) Customer agrees to make any necessary changes or adjustments to the additional facilities being operated in parallel to eliminate interference on Utility's distribution system.

(f) Customer's system shall not energize Utility's system during period of utility service interruption.

* (g) Service under Rider P is subject to and governed by the provisions of the Illinois Commerce Commission's general orders and particularly General Order 214 or subsequent amendments or modifications thereof.

*Asterisk Indicates Change.

ILLINOIS POWER COMPANY
SCHEDULE OF RATES FOR ELECTRIC SERVICE

153RD
REVISED FUEL COST ADJUSTMENT

SUMMARY OF FUEL COST ADJUSTMENTS FOR 24-MONTH PERIOD ENDING WITH CURRENT MONTH

Month	Year	Fuel Cost Adjustment (Per Kwh) (1)	Automatic Reconciliation Factor c/Kwh (2)	Average Fuel Cost c/Kwh (3)
February	1984	.131c	-	1.881c
January	1984	(.170)c	(.176)c	1.756c
December	1983	(.288)c	(.162)c	1.624c
November	1983	(.029)c	-	1.721c
October	1983	.494c	.204c	2.040c
September	1983	.492c	.204c	2.038c
August	1983	.228c	.180c	1.798c
July	1983	(.106)c	-	1.644c
June	1983	(.330)c	(.158)c	1.578c
May	1983	(.377)c	(.153)c	1.526c
April	1983	(.351)c	(.156)c	1.555c
March	1983	(.118)c	-	1.632c
February	1983	.022c	-	1.772c
January	1983	.349c	.191c	1.908c
December	1982	.020c	-	1.770c
November	1982	(.047)c	.001c	1.702c
October	1982	.109c	-	1.859c
September	1982	.070c	-	1.820c
August	1982	(.051)c	-	1.699c
July	1982	(.059)c	-	1.691c
June	1982	(.073)c	-	1.677c
May	1982	(.040)c	-	1.710c
April	1982	(.035)c	-	1.715c
*March	1982	(.082)c	-	1.668c

*Illinois Commerce Commission new Uniform Fuel Adjustment Clause implemented. The new clause with a base fuel cost of 1.750c per kilowatthour was effective with cycle one in March, 1982. Under the Uniform Clause, the Fuel Cost Adjustment is equal to the difference between the Average Fuel Cost and the Base Fuel Cost plus a cost attributed to the operation of an automatic reconciliation factor.

Date submitted: January 31. 1984

ILLINOIS POWER COMPANY

COST OF POWER ADJUSTMENT

1. Applicability

Any Electric Cooperative Customer served by Illinois Power Company (Company) or any Wholesale Municipal Customer served under the provisions of Agreements for Wholesale Electric Service for Resale (Full Requirement) or Agreements for the Purchase of Power (Partial Requirements) which has been entered into with the Company and accepted by the Federal Energy Regulatory Commission (FERC) is subject to the Cost of Power Adjustment (CPA).

2. Customers Subject to CPA Charges

The CPA is applicable to the following Customers:

	Wholesale Customers	
Electric Cooperatives	Full Requirements	Partial Requirements
Clinton County Electric Coop.	City of Oglesby	City of Princeton
Corn Belt Electric Coop.	Village of Ladd	City of Waterloo
Farmers Mutual Electric Coop.	Cedar Point Light & Water Company	City of Peru
Illinois Valley Electric Coop.	* Mt. Carmel Public Utility Co.	City of Mascoutah
McDonough Power Coop.		Village of Freeburg
Monroe County Electric Coop.		City of Breese
Southwestern Electric Coop.		City of Carlyle
Tri-County Electric Coop.		City of Highland
Western Illinois Power Coop.		

3. Cost Factor Determination

The monthly CPA factor is the monthly cost of power minus the base cost of fuel. The monthly cost of power is the cost per kilowatthour of fuel consumed in the Company's generating plants, adjusted for line losses, plus the net cost of energy sold to other utilities during the previous month.

4. Base Cost of Fuel

The following base cost of fuel is included in the effective agreements for electric service:

(a) Electric Cooperatives: 1.70c effective with billings on and after June 1, 1982. The previous base cost of fuel was 1.410c.

(b) Full Requirement Wholesale Customers: 1.550c effective with billings on and after November 15, 1981. The previous base cost of fuel was 0.834c.

(c) Partial Requirements Municipalities: 1.550c effective with billings on and after June 15, 1981. The previous base cost of fuel was 0.834c.

*5. Current CPA Factor

The following CPA factors are applicable for billings for the month of February, 1984:

(.082)c per kwh for Electric Cooperatives

.068c per kwh for Wholesale Customers.

*Asterisk indicates change.

ILLINOIS POWER COMPANY

COST OF POWER ADJUSTMENT - PAGE 7

*6. Historic 24-Month CPA Summary

Month	Year	Cost of Power	Cost of Power Adjustment: Electric Cooperatives	Cost of Power Adjustment: Wholesale Customers
February	1984	1.618c	(.082)c	.068c
January	1984	1.793c	.093c	.243c
December	1983	1.707c	.007c	.157c
November	1983	1.735c	.035c	.185c
October	1983	1.773c	.073c	.223c
September	1983	1.829c	.129c	.279c
August	1983	1.890c	.190c	.340c
July	1983	1.613c	(.087)c	.063c
June	1983	1.626c	(.074)c	.076c
May	1983	1.633c	(.067)c	.083c
April	1983	1.547c	(.153)c	(.003)c
March	1983	1.643c	(.057)c	.093c
February	1983	1.527c	(.173)c	(.023)c
January	1983	1.510c	(.190)c	(.040)c
December	1982	1.845c	.145c	.295c
November	1982	1.783c	.083c	.233c
October	1982	1.725c	.025c	.175c
September	1982	1.794c	.094c	.244c
August	1982	1.708c	.008c	.158c
July	1982	1.591c	(.109)c	.041c
June	1982	1.665c	(.035)c 1/	.115c
May	1982	1.690c	.280c	.140c
April	1982	1.708c	.298c	.158c
March	1982	1.827c	.417c	.277c

7. Effective Dates

The CPA became applicable to Electric Cooperatives June 1, 1977.

The CPA became applicable to Partial Requirements Municipalities May 1, 1979.

1/ Effective on June 1, 1982 for billing in June, 1981 the Electric Cooperative Customer's base cost of fuel changed from 1.410c to 1.70c as a result of approval of Docket No. ER82-562-000.

*Asterisk indicates change.

ESTIMATED CAPACITY REQUIREMENTS AND
AVAILABLE CAPACITY FOR WIPCO IN MWe
1983 through 1993

YEAR	TOTAL SYSTEM	WIPCO SERVED	IPC SERVED	CIPS SERVED	REQUIRED RESERVES[2]	DEPENDABLE CAPACITY	EXCESS (DEFICIT)	NEW CAPACITY	ANNUAL LOAD FACTOR
1983[1]	150	41	24	85	11	56	4		44
1984	156	45	25	86	11	56	0		46
1985	156	45	25	86	11	56	0		46
1986	158	46	25	87	11	56	(1)		47
1987	161	124	0	37[4]	22	146	0	90[3]	47
1988	163	124	0	0	22	146	(39)[5]		47
1989	166	124	0	0	22	146	(42)		47
1990	169	124	0	0	22	146	(45)		47
1991	172	124	0	0	22	146	(48)		47
1992	175	124	0	0	22	146	(51)		47
1993	178	124	0	0	22	146	(54)		48
1994	180	124	0	0	22	146	(56)		48

NOTES:
1 Actual data
2 Calculated at 18% of WIPCO served load or 1/2 of largest unit except Clinton Unit I
3 WIPCO's 9 1/2% share of Clinton Unit I
4 Fixed by contract
5 Beginning in 1988, all excess capacity needs to be purchased through interconnections

EXHIBIT W-1
2/13/84