ILLINOIS POWER COMPANY

ILLINOIS COMMERCE COMMISSION

DOCKET NO. 01-0432

EXHIBITS SPONSORED BY LEONARD M. JONES

OCTOBER 10, 2001

TABLE OF CONTENTS

ILLINOIS COMMERCE COMMISSION

DOCKET 01-0432

REBUTTAL TESTIMONY OF LEONARD M. JONES

OCTOBER 10, 2001

I. Introduction and Purpose of Testimony

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

A. Leonard M. Jones, 500 South 27th Street, Decatur, Illinois 62521. I am Director – Business Planning and Forecasting for Illinois Power Company.

2. Q. Have you previously submitted direct testimony and exhibits in this proceeding?

A. I previously submitted IP Exhibits 6.1 through 6.5.

3. Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to portions of the direct testimony of Staff witnesses Lazare and Haas, IIEC witnesses Stephens and Phillips, and People of the State of Illinois ("AG")/Citizens Utility Board ("CUB") witnesses Effron and Smith concerning billing determinants, revenue allocation, and rate design issues.

4. Q. In addition to IP Exhibit 6.6, your prepared rebuttal testimony, are you sponsoring other exhibits?

A. Yes, I am sponsoring IP Exhibits 6.7 through 6.13, which were prepared by me or under my direction and supervision.

II. Revenue Allocation

5. Q. Mr. Lazare proposes to allocate revenue requirement responsibility to each rate class strictly based on embedded cost of service. Do you accept his approach?

A. The approach used in my direct testimony was the approach used in IP's 1999 DST case. However, for purposes of this case, the Company is willing to adopt Mr. Lazare's approach, and allocate the revenue requirement based solely on cost of service.

6. Q. Does the Company agree with Mr. Lazare that IP's original proposal was fundamentally flawed?

A. No. The Company's original proposal uses the same approach that was approved by the Commission in the 1999 DST case. The rationale that the Company offered and the Commission accepted has not changed. Prices for lighting customers were set based on the bundled charge less the energy component included in the bundled rates. This rate design allowed customers to choose an alternate energy supplier for lighting based on the comparisons to the energy cost embedded in the Company's bundled rate.

7. Q. Then why are you accepting Mr. Lazare's approach?

A. Experience to date indicates that lighting customers that switch to delivery service do so because the lighting account is tied to other, non-lighting service accounts of the customer. Thus, the prices for lighting service have been of little consequence in the customer's decision to elect delivery service. Given the apparent irrelevance of lighting rates in the lighting customer's switching decision, and Mr. Lazare's desire to allocate the revenue requirement based solely on cost of service, the Company has elected to accept Mr. Lazare's revenue allocation approach.

8. Q. Have you allocated IP's rebuttal revenue requirement to the rate classes based on the revised embedded cost of service study performed in Ms. Althoff's rebuttal testimony?

A. Yes. The results are shown in IP Exhibit 6.7.

III. Billing Determinants

9. Q. Have revisions been made to IP's billing determinants as discussed by Staff witness Lazare at pages 43-44 of his direct testimony and by IIEC witness Phillips at page 18 of his direct testimony?

A. Yes. The revised billing determinants are provided in IP Exhibit 6.8.

10. Q. Please briefly describe the revisions made to the billing determinants.

A. First, revisions were made to residential kWh totals to account for weather normalization of the unbilled sales total. Second, the number of customers apportioned between the low voltage "up to 200 kW" demand metered group and the non-demand metered non-residential group were adjusted to properly reflect the number of customers that qualify for Small Use General Service. Since customers moved from one group to another, the kWh and kW associated with those customers were also moved to the appropriate class. Third, the demand values used for "Demand Charge" inadvertently reflected a 12 month maximum demand rather than 12 individual monthly maximum demands. The correct values are shown in IP Exhibit 6.8.

11. Q. Have you reviewed AG/CUB witness Effron's testimony regarding the Company's billing determinants?

A. Yes, I have. Mr. Effron recommends the Company's billing determinants be annualized to reflect the end of test year number of customers and an annualized energy sales level based on the end of year number of customers. The Company has made the changes to the residential billing determinants suggested by Mr. Effron using the same procedures he employed. In addition, the Company has made similar adjustments to the billing determinants for the non-residential customer groups. These calculations are show in IP Exhibit 6.9, and are reflected in IP Exhibit 6.8.

12. Q. Why was the number of residential customers counted in December 2000 lower than the average for the year?

A. Monthly customer counts are based on the number of bills issued in the month. Therefore, monthly customer counts can vary depending on the number of bills issued in the month. In most months, customers are billed once, but in some months, some customers are billed twice, or not at all. Over the course of a year, the customer count evens out to provide an accurate representation of the average for the year.

IV. Rate Design

13. Q. Have you reviewed the discussions of Staff witness Lazare and IIEC witness Phillips regarding the Company's rate design proposal?

A. Yes. Mr. Lazare and Mr. Phillips request some more specific explanation for the Company's proposed rates.

14. Q. Have you developed a more detailed explanation of the development of the Company's proposed rates?

A. Yes. A methodology statement is provided in IP Exhibit 6.10. The methodology statement shows how the Company's rates are based on embedded costs, and how marginal costs are used as a guide in some pricing development. To a large extent, the methodology statement provides a narrative guide to the information provided in the Company's workpapers supplied in response to Staff Data Request AD-01. Further, the Company's approach to developing demand charges is similar to that used in the 1999 DST case.

15. Q. Have the Company's proposed rates changed as a result of changes to the electric distribution revenue requirement presented by other IP witnesses and summarized by Mr. Mortland in his rebuttal testimony?

A. Yes. The proposed rates and resulting revenue presented in this testimony are based on the Company's rebuttal revenue requirement values presented by Mr. Mortland. The proposed rates, and a comparison between present and proposed rates, are shown in IP Exhibit 6.11. It should be noted that, as in other cases, the use of rounded rate numbers means that certain values have to be slightly adjusted to keep rate recovery balanced with the revenue requirement.

16. Q. Have you considered the testimony of AG/CUB witness Smith concerning the rate design for the residential class?

A. Yes, I have. Ms. Smith proposes to keep the facilities charges for delivery service identical to those in bundled rates, and also proposes that the differential between the first and second energy block be the same as in current bundled rates. Specifically, Ms. Smith proposes Facilities Charges of $6.33, $8.46, and $17.00 for multi-family, single family, and three-phase service, respectively. Further, Ms. Smith proposes a first block delivery charge differential that is 0.8 cents/kWh higher than the tail block delivery charge. Although I can accept Ms. Smith's approach in concept for purpose of this case, there are two implementation issues. First, Ms. Smith's proposed Facilities Charges are equal to existing SC 2 Facilities Charges. However, on May 1, 2002, residential rates will be reduced by another 5% (from the rates in effect in December, 1997). The Facilities Charges that will be in effect on May 1, 2002, for SC 2 will be \$5.96, \$7.96, and \$16.00 for multi-family, single family, and three-phase service, respectively. Second, Ms. Smith proposes to use 0.8 cents/kWh to differentiate the first block delivery charge from the tail block delivery charge. However, 0.8 cents/kWh is the <u>summer</u> season price differential that will be in effect for SC 2 on May 1, 2002. The winter season price differential will be 1.76 cents/kWh. The load weighted (by seasonal kWh usage) differential is 1.4 cents/kWh. Thus, using Ms. Smith's methodology for pricing residential service, the Facilities Charges for SC 2 and the load-weighted summer and winter per kWh first block price differential in effect on May 1, 2002 should be used.

17. Q. How do Ms. Smith's proposed prices compare to the values generated by the Company's cost based rate design approach?

A. A comparison of the Facilities Charges may be found in IP Exhibit 6.10 (Schedule 2, item 1, page 5). The single family Facilities Charge from SC 2 (on 5/1/2002) is very close to the cost of service (\$7.96 price vs. \$8.25 cost), while the multi-family Facilities Charge is well below cost of service (\$5.96 price vs. \$7.13 cost) and the three-phase

Facilities Charge is above cost of service ($16.00 price vs. $13.34 cost). Using the Company's rate design methodology outlined in IP Exhibit 6.10 (Schedule 2, item 3, page 7), the first block delivery charge would have been 0.9 cents/kWh higher than the tail block. Again, the Company's rate design methodology would have generated results close to the methodology proposed by Ms. Smith.

18. Q. What do you conclude regarding Ms. Smith's proposed residential rate design methodology?

A. Given that delivery service will be a new experience for residential customers, Ms. Smith argues that greater weight should be given to maintaining continuity between bundled and delivery service rates, which would contribute to simplicity and customer understanding (AG/CUB Ex. 1, p. 12). While her approach differs from the Company's proposal, the results are reasonably close. Therefore, the Company will use Ms. Smith's residential rate design approach, modified to adjust Facilities Charges for the additional 5% rate decrease to become effective on May 1, 2002, and to adjust the first block delivery charge differential to match the combined load-weighted summer/winter first block energy charge differential in SC 2 under the rates to be in effect May 1, 2002. Movement to fully cost based rates may be made in subsequent proceedings after evaluating customer reaction to the initial delivery service rates.

19. Q. How does the AG/CUB residential rate design proposal compare to the proposal offered by Staff witness Lazare?

A. Mr. Lazare also proposed to use the existing facilities charges for bundled SC 2 as the starting point. However, Mr. Lazare proposes to use a flat energy charge to recover the remaining allocated revenue requirement in order to send consumers in higher usage brackets a price signal to conserve energy. He states that "The higher rate applying to higher usage levels would encourage these customers to reduce wasteful consumption; thereby mitigating upward pressure on power prices and benefiting the environment accordingly." (Staff Exhibit 5.0, p. 39).

20. Q. AG/CUB witness Smith (AG/CUB Ex. 1, p. 12) also states that the 300 kWh block will give customers less incentive to conserve usage. Is encouraging conservation an appropriate rate design objective for delivery service rates at this time?

A. I question whether encouraging conservation in electricity use should be a consideration in setting rates of a delivery services provider that does not supply energy. Putting that aside, however, price signals sent to consumers should reflect the cost of providing the service to the consumer. One of the consequences of establishing cost-based prices is that, if unit costs increase as one serves additional customer load, the unit price will likewise increase, giving customers an incentive to conserve energy. In the example provided by Mr. Lazare, he indicated that it is reasonable to assume that a customer using 3,000 kWh per month would require larger secondary facilities than a customer using 300 kWh per month. (Staff Exhibit 5.0, p. 38) While it costs more in total dollars to serve a larger residential customer than a smaller customer, doing so is cheaper on a cents/kWh basis. For example, IP Exhibit 6.12 shows that for secondary level systems, it costs $52/year to serve each customer who uses only 300 kWh per month served off that circuit. For customers that use 3,000 kWh per month, the secondary level systems necessary to serve each customer cost $79/year. For the 300 kWh per month customer, this equates to over 1.4 cents/kWh, while for the 3,000 kWh per month customer, this only amounts to 0.2 cents/kWh. Thus, as customers with a typical load pattern increase in size, secondary voltage level systems needed to serve the customer decrease in cost per kWh. This also demonstrates that a declining block rate is appropriate, and that a flat delivery rate per kWh would provide a subsidy from the larger residential customer to the smaller residential customer. The same is true for Small Use General Service Customers.

21. Q. The example in IP Exhibit 6.12 shows that it typically costs more in absolute dollars to serve a larger customer. Why then has the Company proposed to recover all secondary costs in the first 300 kWh delivery charge?

A. First, secondary facilities are installed as a function of the number of customers and expected demand on the facilities. IP Exhibit 6.12 indicates that the secondary system cost is heavily weighted toward a function of the customer being connected to the Company's system. As such, the cost may be best recovered through a fixed facilities charge. The demand or usage sensitive portion of the cost is relatively small. In effect, the incremental cost of secondary service to larger customers is only 0.08cents/kWh [($78.73 – $52.01)/(36,000kWh-3,600kWh) = 0.08cents/kWh]. Second, 99% of the Company's residential customers use less than 3,000 kWh per month. Nearly 80% of the Company's residential customers use less than 1,150 kWh per month, and 50% of residential customers use less than 650 kWh per month. The embedded cost of the facilities was incurred to serve all of the Company's residential customers, and as such are heavily weighted toward facilities that are designed to serve an average (smaller) customer. While the 1% of secondary facilities constructed to serve customers using 3,000 kWh per month or more are indeed included in the average, the 20% of customers who do not use 300 kWh per month are likewise included. Thus, on balance, the Company's proposal is reasonable and equitable to all customers. Next, in a rate class with over 500,000 customers, there are bound to be situations where the rate design does not seem adequate to properly recover a particular customer's cost of service. For instance, the Company serves customers in both urban and rural areas, and with overhead service and underground service. In the interest of rate simplicity, the Company has not addressed cost of service differences arising from urban vs. rural locations and overhead vs. underground service in rate design. Similarly, recovering the secondary voltage system costs in the first block delivery charge is fair for the vast majority of the Company's customers. Finally, not all customers use 300 kWh per month. Only approximately 80% of residential customers consistently use more than 300 kWh per month. Thus, some smaller customers do not fully pay for secondary facilities that serve them.

22. Q. Has the Company considered IIEC witness Stephens' complaint that the shifting of revenue responsibility from lower voltage customers to higher voltage customers has increased rates to the high voltage customers too much?

A. Yes. The Company's proposal in direct testimony based the non-residential facilities charges on the total embedded customer cost methodology as outlined in IP Exhibit 6.10. In order to mitigate some of the rate impact of moving prices to cost of service immediately, the Company is now proposing to move the price of the combined facilities and metering charge one-half of the way between the current delivery service price and the cost of service. The adjustment created in this step will be applied to the Facilities Charge. The metering charge will be set equal to cost of service, since this is an unbundled service that may be provided by others. This approach will also increase the revenue recovery from the lower voltage customers as compared to IP's original proposal, thereby allowing for a lower charge to higher voltage customers. The mechanics of the Company's proposal are outlined in IP Exhibit 6.10.

23. Q. With the adjustment to Facilities Charges described above, what is the Company's rate design proposal for Small Use General Service metered customers?

A. The Company proposes Facilities Charges of $8.03 and $11.09 for single and three-phase service, respectively. Further, the Company proposes Metering Charges of $3.35 and $7.78 based on the unbundled metering ECOSS results provided by IP witness Althoff in her rebuttal testimony and the methodology outlined in IP Exhibit 6.10. The Delivery Charge maintains a first block of 300 kWh priced higher than the tail block for the reasons discussed above for the residential class. Secondary system costs form the basis for the rate differential, and the development of the charge is shown in IP Exhibit 6.10 (Schedule 2, item 3, page 7). The total Delivery Charge has been reduced by an amount of the subsidy created by the higher facilities charge as show in IP Exhibit 6.10 (Schedule 2, item 3, page 7).

24. Q. Do you have any comments on Mr. Lazare's criticism of the Company's proposed delivery charge for unmetered customers?

A. Mr. Lazare criticized the Company's rate design for unmetered service because the delivery charge increased by 723% from $0.0014 to $0.01152 cents/kWh. However, Mr. Lazare is proposing an 1176% increase, from $0.0014 to $0.01787 per kWh for this rate element. The Company's proposal simply keeps the unmetered service Facilities Charge at the existing delivery service level, and recovers the remaining allocated revenue requirement through the Delivery Charge.

25. Q. What impact did limiting the Facilities Charge movement as described above have on the calculation of demand charges for non-residential Demand Metered customers?

A. The Facilities Charge methodology increases revenue recovered over the level of cost of service, which provides a subsidy from the customer cost to the demand cost category. The Facilities Charge subsidy was shared among each voltage level of service according to each voltage level's demand related cost of service relative to the total. The methodology is shown on IP Exhibit 6.10, Schedule 2, item 3, page 1. In short, the Facilities Charge subsidy reduces the demand charges for all customers (including higher voltage customers). The Company's proposed rates are shown in IP Exhibit 6.11 and the methodology used to develop the rates is described in IP Exhibit 6.10.

26. Q. In addition to the Facilities Charge impact described above, have you changed the demand charge development methodology from the Company's direct case filing?

A. Yes. In addition to the Facilities Charge change described above, the Company has also refined its approach as to how other demand cost offsets were apportioned to the various voltage levels. As shown in IP Exhibit 6.10 (Schedule 2, item 3, page 1), Transformation Charge revenue and miscellaneous revenue also provide some cost offsets. In the Company's direct case, demand prices were created by applying the entire Transformation Charge revenue offset to the primary voltage demand cost. The Company now proposes to apportion the revenue offset according to the ratio of the transformation demand at each voltage level to the total transformation demand. The revised approach recognizes that customers who do not use the primary voltage system also pay a Transformation Charge.

Similarly, in the Company's direct case, miscellaneous revenue provided a demand cost offset based on the ratio of the ECOS demand at each voltage level to the total ECOS demand. The majority of miscellaneous revenue collected from demand metered customers is for rental service of equipment (e.g., transformers and substations) and as such, should provide a cost offset to the voltage costs at the voltage level where the customer takes service. Rental service costs that were directly identified with a customer were credited to the appropriate voltage cost where the customer takes service. The costs that were not directly identified with a customer were allocated based on the ratio of the ECOS demand at each voltage level to the total ECOS demand. All of these steps have the impact of reducing demand charges for higher voltage customers.

27. Q. What are the proposed revenue increases for the three demand metered customer categories shown on IP Exhibit 6.8?

A. The revenue increase for customers up to 200 kW would be 39%; the revenue increase for customers with demands from 200 – 1,000 kW would be 36%; the revenue increase for customers over 1,000 kW would be 39%.

28. Q. What are the rate impacts of the Company's rebuttal rate design for customers over 5 MW?

A. Using the examples provided by IIEC witness Stephens (at page 8 of his direct testimony), the percent revenue increases to customers at various voltage levels is as follows: 12.47 kV and below: 16%; 34.5 kV to 69 kV: 55%; 138 kV and above: 75%. The increases on a per kWh basis are 0.066 cents/kWh, 0.048 cents/kWh, and 0.065 cents/kWh, respectively.

Further, contrary to Mr. Stephen's assertion, most customers over 1 MW would pay a Transition Charge ("TC") if they switched from bundled service today. Of the customers still served under bundled rates, all SC 21 and SC 24 customers, if eligible to switch, would pay a TC if they switched by the end of October. The simple average TC for SC 21 customers is approximately 2.25 cents/kWh and nearly 1.0 cent/kWh for SC 24 customers. Thus, to the extent that these customers were to switch to delivery service, the delivery service rate design impact will be absorbed by the customer's transition charge. In other words, the impact of the delivery service rate change will not be felt by the customer, or the Company, in terms of total revenue paid and collected. Further, if a customer does not have a TC, this is because the customer's bundled service rate is near or below the cost the customer would incur for power in the competitive market, plus delivery services (i.e., what the competitive market could offer the customer).

29. Q. Mr. Stephens and Mr. Lazare both request additional support for the Company's proposed Reactive Demand Charge. What support does the Company have for its proposed $0.20/kVAR charge?

A. The basis for the proposed charge is presented in IP Exhibit 6.10 (Schedule 2, item 5). The charge is based on the cost of installing new capacitor banks, plus applicable expenses. Use of the cost of a newly installed capacitor bank appropriately reflects the economic decision that customers face – either take steps to minimize kVAR demand or pay the Company's Reactive Demand Charge. Further, customers are free to install their own capacitors to reduce kVAR's measured by the Company's meter. For customers that own their own generation facilities, VAR's may be produced by the generation facilities which would also offset kVAR's measured by the Company's meter. Additionally, an increase in this charge serves to reduce the demand costs recovered in other demand charges for customers over 1 MW. IP Exhibit 6.10 (Schedule 2, Item 3, Page 6). Thus, customers with better power factors benefit from overall lower rates. Further, the current bundled service Reactive Demand Charge is $0.30/kVAR. Thus, as customers move from bundled rates to delivery services, they will still see a decrease in the price paid for this component of service.

30. Q. Similarly, Mr. Stephens and Mr. Lazare also both request additional support for the Company's proposed Transformation Capacity Charge. What support does the Company have for its proposed $0.50/kW charge for customers under 3 MW and $0.75/kW for customers 3 MW and over?

A. The basis for the proposed charge is presented in IP Exhibit 6.10 (Schedule 2, item 4). The charge is based on the cost of installing new transformers, plus applicable expenses. Use of the cost of a newly installed transformer appropriately reflects the economic decision that customers face – have power transformed by the Company, or provide their own transformation, through ownership or lease of facilities. Customers are free to install their own transformers to transform power from the customer's supply voltage to the voltage needed by the customer. Further, revenue collected from Transformation Charges serves to reduce the demand costs recovered in other demand charges for all demand metered customers. Thus, customers who rent or own their transformation facilities do not pay for the service twice, and benefit from lower demand rates. Further, the current bundled service Transformation Capacity Charge is $0.75/kW. As customers move from bundled rates to delivery service, they see a decrease in price paid for this service if under 3 MW, or pay the same price if 3 MW or larger.

31. Q. Mr. Stephens questions the price differential in the Transformation Charge for customers above and below 3 MW. Do you have any response?

A. Yes. First, IP witness Voiles explains the history behind the Transformation Charge for customers 3 MW and above. I also note that of 73 IP customers larger than 3 MW, 57 already own or rent their transformation facilities. Thus the charge would apply at most to 16 customers. Moreover, the $0.75/kW Transformation Charge for customers over 3 MW is within the range of costs of recently installed facilities, as shown in IP Exhibit 6.10 (Schedule 2, item 4). Customers 3 MW and over have demonstrated a willingness to either rent or own their transformation facilities. If the rate for customers above 3 MW is set too low (any amount below $0.75/kW) other customers will eventually pay the cost to serve via higher demand charges as customers requiring expensive transformation facilities take the cheaper Transformation Charge, leaving the remaining cost of serving the customer to be shared by all other customers. Further, customers over 3 MW typically require substations to transform their power. Substation costs can vary considerably from customer to customer. One customer may desire additional fault protection equipment, while another may not. One customer's transformation facility may need to be placed on a concrete pad secured with a fence, while another customer's facilities may be pole mounted. Such customer preferences and circumstances can cause cost differences. For this reason, the Company would prefer to require customers 3 MW and over to rent or own their transformation facilities. However, for reasons explained by Ms. Voiles, the Company currently has in place a $0.75/kW Transformation Charge for customers 3 MW and over.

32. Q. Could the Transformation Charge be based on embedded costs, as Mr. Stephens proposes?

A. No. The Company's property accounting system does not provide sufficient detail to determine if a transformer or substation is connected directly to a customer's delivery point or not. Accordingly, incremental cost pricing for this service is the most practical (and reliable) approach, and is consistent with the method used to set these rates in the 1999 DST case.

33. Q. Mr. Lazare takes issue with the Company's proposal to establish a Distribution Capacity Charge for demand metered customers, based on the customer's maximum demand experienced in the past 12 months. Specifically, Mr. Lazare states:

> While use of the 12 month peak magnifies the importance of the customer's peak as a signal to control demands, it diminishes the need to control monthly peak demands, which have no effect on the Distribution Capacity Charge as long as they remain below the 12 month peak. (Staff Exhibit 5.0, p. 31)

Please respond.

A. First, Mr. Lazare is correct that basing charges on Distribution Capacity magnifies the importance of the customer's peak demand as the basis for a signal to control demands. Indeed, cost of service studies (including the one used in this proceeding) use a non-coincident peak demand for the year to allocate distribution costs. This method recognizes that it is the annual peak demand that drives distribution investment. Use of Distribution Capacity, rather than the customer's monthly peak demands, better follows the manner in which costs were incurred (and assigned). Next, while there is an emphasis on the customer's annual peak, customers still have an incentive to keep peak demands in other months low. Twelve months following the customer's setting of a peak demand, the customer's next highest demand will become the new Distribution Capacity. Customers still have an incentive to pay attention to their demand to set a lower demand for the future. Third, one year from now, a customer may have the same amount of demand as it has today. Monthly demands are of little consequence once the maximum demand for a distribution circuit is set. The equipment in that circuit will still need to serve the expected maximum demand. What matters more than monthly peaks is the maximum potential for the peak. Fourth, use of the Distribution Capacity as the basis for a Distribution Capacity Charge ensures that higher load factor customers do not subsidize lower load factor customers. If the Distribution Capacity were discarded in favor of the monthly maximum demand, the unit rate would increase. Under the Company's cost based rate design methodology shown in IP Exhibit 6.10, using the smaller maximum monthly demand would increase the unit rate. Thus, a high load factor customer would likely pay more under Mr. Lazare's method than the low load factor customer.

A simple example illustrates this point. Assume two customers are on the same circuit. The first customer has a peak demand of 2 MW around the clock (100% load factor). The other customer also has a peak demand of 2 MW, but in 11 months of the year, only 500 kW is used. Thus, for the circuit, a total deliverability of 4 MW is needed. Further assume that the annual revenue requirement is $100,000 for the distribution system. Under the Distribution Capacity approach, each customer would pay the Company the same amount for delivery service, or $50,000 (ignoring for the moment the Demand Charge). This is appropriate since each customer contributed equally to the need for the Company to install 4 MW of distribution capacity. Under Mr. Lazare's approach of using monthly maximum demand, the high load factor customer would pay $76,190 per year while the second customer would only pay $23,810. The result is that customer 1 provides a subsidy to customer 2, and that customer 1 would now have an incentive to reduce demand to lower the total cost burden, while customer 2 has less of an incentive to control his annual peak demand. In fact, under Mr. Lazare's maximum monthly demand approach, customer 2's maximum annual demand would have to reach 18,500 kW before customer 2's payment to the Company equaled that paid by customer 1. Of course, at this demand level, total circuit system demand would be 20,500 kW and customer 1 would be contributing less than 10% to the circuit peak demand. See IP Ex. 6.13.

34. Q. Mr. Lazare also mentions that the Commission has recently moved away from ratchet demand rates, citing a ComEd and an Ameren case. How do these cases differ from what the Company is proposing?

A. In both cases, the utilities appeared to be proposing to recover the entire delivery service charge through rates that were subject to a demand ratchet. IP is proposing only to recover the cost of local primary and secondary voltage systems through the Distribution Capacity Charge. Customers that pay the Distribution Capacity Charge are also subject to the Demand Charge, which is based on the customer's monthly maximum demand. Thus, customers still have an immediate incentive to monitor their monthly maximum demands. Further, the proposed SC110 Distribution Capacity Charge is similar to the Distribution Capacity Charge in existing bundled rates for demand metered customers.

V. Standby Capacity Requirement

35. Q. Have your reviewed IIEC witness Stephens' and Staff witness Haas' testimony regarding the Company's proposed standby capacity requirement?

A. Yes. Mr. Stephens and Mr. Haas both object to the tariff provision that specifies that if a self-generation customer using delivery services for stand-by exceeds its standby capacity, the customer will then be charged an amount equal to three times the otherwise applicable demand charges for the excess demand. Both witnesses also object to use of billing determinants that they contend differ from those used for all other customers.

36. Q. How do you respond to the criticisms of the charges applicable when a self-generation customer exceeds its standby contract amount?

A. Under IP's proposal, if a customer exceeds the standby contract capacity in any amount, the customer would be billed 3 times the otherwise applicable demand charges for the excess demand. The Company proposed this provision to give customers an incentive to choose the level of standby capacity that fits their particular situation. Without the provision, the Company believes that customers would have an incentive to choose a standby capacity value that is lower than what their actual delivery service needs would be if their self-generation facilities went off-line. However, given the difficulty in predicting exactly the appropriate standby capacity level, the Company now proposes that as long as the customer's demand does not exceed the standby capacity value by more than 10%, the three times charge will not apply. However, if the customer's actual demand exceeds the standby capacity, the standby capacity will still be reset to equal the customer's new actual demand. Further, if a new standby capacity value is established, the company will review the customer's standby capacity requirement after 12 months, based on the customer's demands in the intervening period and its connected load, to determine if the customer's standby requirement should be lowered.

37. Q. How do you respond to the argument that standby customers are being treated differently (i.e., use of different billing determinants) than other customers?

A. These customers have different billing determinants because they operate differently than other customers. As stated in my direct testimony, in the absence of the standby capacity requirement, the customer would receive standby service for his full load, but only pay for a portion of the cost. The standby capacity requirement helps ensure that other customers do not subsidize the delivery service standby customer. Is essence, the standby capacity requirement is like an insurance payment and requires self-generation customers to pay for the delivery service that they are receiving. Whether or not the delivery service system was actually used by the customer to provide energy to its facilities, the insurance was still provided.

38. Q. What about the fact that the non-self-generation customer is billed for delivery service based on a non-ratcheted demand, while the self-generation customer is billed based on a ratcheted demand?

A. For billing determinants that use the customer's twelve-month maximum demand, billing determinants established using the customer's standby contract capacity and those using the customer's Distribution Capacity will likely be similar. The customers with self-generation on the Company's system appear to have established their maximum distribution system peak in the past 12 months. Thus, for those customers, their standby capacity and their Distribution Capacity may be identical. However, for billing determinants that otherwise would use the monthly maximum demand (i.e., Demand Charge) if the customer did not have generation, the standby customer would pay more for Delivery Service. To address this issue, the Company now proposes to use the self-generation customer's standby capacity multiplied by a load diversity factor to adjust the customer's standby capacity to approximate a monthly maximum demand. Use of a diversity factor is consistent with the approach used in the Company's SC 22, Standby Service, and effectively converts the customer's standby capacity to a billing determinant that is more representative of the monthly maximum demand. The adjustment will only apply to the customer's billing determinants used for the Demand Charge.

39. Q. Please describe how the load diversity factors were developed.

A. The factors were taken from the load profile workpapers associated with Rider TC. For higher load factor customers, information from profile 601 (SC 24) will be used. For other large customers (over 1 MW), profile 501 (SC 21) will be used. For customers under 1 MW, profile 407 (SC 19 - miscellaneous) will be used. The resulting diversity factors were developed by taking the average of the monthly maximum demands divided by the maximum annual demand. The diversity factors are 85%, 80%, and 75%, respectively. These factors have been applied to the Standby Capacity Requirement for purposes of calculating the customer demand charges reflected in IP Ex. 6.8.

40. Q. How will you determine which load diversity factor applies to a customer?

A. The determination will be based on an estimate of the customer's load factor assuming that the customer's generation were idle for the year. Customers with a 50% or better load factor will fall under the SC 24 diversity factor, while customers with lower load factors will have the SC 21 diversity factor applied.

41. Q. Mr. Haas appears to oppose use of the standby capacity requirement even for establishing the billing determinant for the Transformation Capacity charge. What is your response?

A. I disagree with Mr. Haas on this point. At a minimum, the standby capacity requirement should apply fully to the Transformation Capacity Charge in SC 110, section 6.C(5). Customer transformers or substations must be sized to serve the customer's maximum expected demand at any single moment. Use of a twelve month maximum demand may not appropriately reflect the self-generation customer's expected maximum demand that could be placed on the delivery system. The standby capacity requirement provides the appropriate basis to bill for the Transformation Capacity Charge.

42. Q. Mr. Haas also states that IP has failed to consider load diversity among self-generation customers and their benefits provided to the delivery system. Please comment.

A. Mr. Haas believes that it is unreasonable to make standby customers responsible for paying for the amount of potential usage that the customer would be drawing from the grid if self-generation did not exist. Mr. Haas also provides an example of 100 customers who install on-site generation to serve a portion of their load, in order to demonstrate that these are diversity benefits of having many self-generation customers connected to the delivery grid. Mr. Haas may not be familiar with the IP system and the number of self-generation customers connected to the grid. At this time, IP only has 9 self-generation customers, spread across its system of nearly 800 distribution circuits, so these customers would not provide any load diversity benefits. The self-generation customer places the same planning burden on the Company as do other customers. The level of investment in distribution facilities to provide, or be prepared to provide, delivery service to these customers is the same. It would be irresponsible for distribution planners to assume that a customer's generation facility would be running at the time of the local circuit peak. If the planners were to do so, they would do so at the risk of a degradation in reliability.

43. Q. Mr. Haas believes that IP has proposed the standby capacity requirement as a means to mitigate the risk of revenue lost to the Company or an affiliate due to additional proliferation of self-generation (Staff Exhibit 9.0, p 6-7). Please comment.

A. The Company proposed the standby contract requirement in order to recover the Company's distribution system costs of backing up the load that is served by a customer's self-generation equipment, but that is not isolated from the Company's distribution system. As it stands today, the Company's other customers are paying a portion of the cost of standing by ready to provide delivery service to the customer with self-generation. The Company is simply attempting to recover the cost of providing service from those who impose the cost on the Company.

44. Q. Can you provide an example to illustrate the points raised above?

A. Yes. Consider a hypothetical similar to the one discussed in connection with the Distribution Capacity charge. Assume a circuit serves two customers, each with a load (demand) of 2,000 kW. Customer 1 has generation that serves all of its load, and relies on the Company's distribution system in the event of a self-generation outage. Customer

2 does not have self-generation. The revenue requirement associated with the distribution system needed to serve the 4,000 kW demand is $8,000 per month ($96,000 per year), which generates a demand price of $2.00 per kW-month.

Under the Company's proposed standby capacity approach, Customer 1 and Customer 2 would each pay $4,000 per month. This approach does not encourage or discourage customer self-generation, but merely seeks to recover the cost of providing delivery service equitably from each customer.

Under Mr. Haas' approach, Customer 2 would be responsible for the full $8,000 of monthly charges although the Utility's revenue requirement associated with serving his load would only be one-half the amount ($4,000). Customer 1, while necessitating the same investment in delivery systems as Customer 2, would pay nothing unless this customer's generation were to be off-line in a particular month. This approach creates a $4,000 subsidy to be paid by Customer 2 for costs which Customer 1 should be responsible.

45. Q. Does the Company oppose self-generation facilities?

A. No, it does not. On this point, we agree with Mr. Cooper's rebuttal testimony in Docket No. 00-0802 where he stated:

> As indicated above, the Company's interests are in a fair and equitable recovery of its delivery costs from each of its customer classes. Again, it is not the Company's intent to alter the economics of self-generation. The Company's only intent is to implement cost-causation and recovery principles. The Company recognizes that, if self-generation customers are obligated to pay costs that they cause, self-generation may not be as attractive as would be the case if they could avoid those costs and get what amounts to free insurance. This does not indicate any problem with the Company's proposal. Rather, it suggests that failure to adopt

the Company's proposal would create a false incentive for customers to self-generate, at the expense of those who do not.

VI. Rider PRS

46. Q. Have you considered IIEC witness Stephens' criticisms of Rider PRS?

A. Yes. The Company has decided to withdraw Rider PRS as originally proposed. Instead, the Company proposes to retain the provisions found in current Section 13 of SC 110 as the substance for Rider PRS.

47. Q. Does this conclude your prepared rebuttal testimony?

A. Yes it does.

Illinois Power Company
Revenue Allocation for Delivery Service

TME 12-31-2000

Class	Proposed Revenue Requirement	Proposed Miscellaneous Revenue	Proposed Net Revenue Requirement	Proposed Percent of Total
Residential	$ 180,231,000	$ (2,738,000)	$ 177,493,000	61%
Small Use General Service	$ 10,269,000	$ (885,000)	$ 9,384,000	3%
Demand Metered General Service	$ 93,011,000	$ (5,659,000)	$ 87,352,000	28%
Lighting /1	$ 20,636,000	$ (92,000)	$ 20,544,000	7%
Total	$ 304,147,000	$ (9,374,000)	$ 294,773,000	100%

/1 Proposed shows total lighting, including Residential.

Illinois Power Company
Delivery Service Detailed Billing Determinants - Rebuttal
Twelve Months Ending 12-31-00

Class	Monthly Billing Units		Present Unit Charge	Present Annual Revenue	Monthly Billing Units	Proposed Unit Charge	Proposed Annual Revenue	Difference $ - Present v. Proposed	Percent Change
Residential									
Facilities Charge									
Multi-Family	97,819		N/A	$ -	97,819	$ 5.96	$ 6,995,980		
Single Phase	390,942		N/A	$ -	390,942	$ 7.96	$ 37,342,806		
Three Phase	18,231		N/A	$ -	18,231	$ 16.00	$ 3,500,296		
Subtotal	506,992	cust		$ -	506,992		$ 47,839,083	$ 47,839,083	
Delivery Charge									
1st 300 kWh/month #	1,728,869,694	kwh	N/A	$ -	1,728,869,694	$ 0.03422	$ 59,161,921		
Over 300 kWh/month	3,486,334,792	kwh	N/A	$ -	3,486,334,792	$ 0.02022	$ 70,493,690		
	5,215,204,486	kwh	N/A	$ -	5,215,204,486		$ 129,655,610	$ 129,655,610	
Total				**$ -**			**$ 177,494,693**	$ 177,494,693	
Small Use General Service									
Metered									
Facilities Charge									
Single Phase	26,703		$ 9.53	$ 3,053,755	26,703	$ 8.03	$ 2,573,101		
Three Phase	8,408		$ 19.53	$ 1,970,499	8,408	$ 11.09	$ 1,118,937		
Subtotal	35,111	cust		$ 5,024,254	35,111		$ 3,692,038	$ (1,332,216)	-27%
Meter Charge									
Single Phase	26,703		$ 3.47	$ 1,111,913	26,703	$ 3.35	$ 1,073,461		
Three Phase	8,408		$ 3.47	$ 350,109	8,408	$ 7.78	$ 784,971		
Subtotal	35,111			$ 1,462,022	35,111		$ 1,858,431	$ 396,409	27%
Delivery Charge									
1st 300 kWh/month 0	90,815,210	kwh	$ 0.0014	$ 127,141	90,815,210	$ 0.01741	$ 1,581,093		
Over 300 kWh/month	158,814,285	kwh	$ 0.0014	$ 222,340	158,814,285	$ 0.01088	$ 1,727,899		
Subtotal	249,629,495			$ 349,481	249,629,495		$ 3,308,992	$ 2,959,511	847%
Metered Subtotal				$ 6,835,757			$ 8,859,461	$ 2,023,704	30%
Unmetered									
Facilities Charge	2,206		$ 8.50	$ 225,012	2,206	$ 8.50	$ 225,012	$ -	0%
Delivery Charge									
All kWh/month	34,832,958	kwh	$ 0.0014	$ 48,766	34,832,958	$ 0.00859	$ 299,215	$ 250,449	514%
Unmetered Subtotal				$ 273,778			$ 524,227	$ 250,449	91%
Small Use General Service Total				**$ 7,109,535**			**$ 9,383,689**	$ 2,274,153	32%
Demand Metered General Service									
Up to 200 kW									
Facilities Charge									
Single Phase	11,271		$ 35.79	$ 4,840,756	11,271	$ 25.11	$ 3,396,239		
Three Phase									
<2.4 kV	16,338		$ 35.32	$ 6,924,526	16,338	$ 26.93	$ 5,279,657		
2.4-12.47 kV	86		$ 280.14	$ 287,885	86	$ 187.11	$ 192,283		
34.5-69 kV	7		$ 660.54	$ 55,485	7	$ 570.32	$ 47,907		
138 kV	-		$ 1,786.62	$ -	-	$ 1,890.63	$ -		
Subtotal	27,701	cust		$ 12,108,652	27,701		$ 8,916,085	$ (3,192,567)	-26%
Meter Charge									
Single Phase	11,271		$ 5.46	$ 738,489	11,271	$ 8.62	$ 1,165,893		
Three Phase									
<2.4 kV	16,338		$ 15.68	$ 3,074,082	16,338	$ 15.99	$ 3,134,857		
2.4-12.47 kV	86		$ 94.86	$ 97,483	86	$ 148.15	$ 152,246		
34.5-69 kV	7		$ 99.46	$ 8,355	7	$ 354.43	$ 29,772		
138 kV	-		$ 113.38	$ -	-	$ 1,392.79	$ -		
Subtotal	27,701			$ 3,918,408	27,701		$ 4,482,769	$ 564,361	14%
Distribution Capacity Charge <=12.47kV	1,097,854	kw	N/A	$ -	1,097,854	$ 2.579	$ 33,976,400	$ 33,976,400	
Demand Charge (Monthly Max)									
<=12.47 kV	778,409		$ 2.136	$ 19,952,181	778,409	$ 0.488	$ 4,558,363		
34.5-69 kV	12,122		$ 0.263	$ 38,257	12,122	$ 0.474	$ 68,950		
138 kV	-		$ 0.016	$ -	-	$ 0.026	$ -		
Subtotal	790,531			$ 19,990,438	790,531		$ 4,627,313	$ (15,363,124)	-77%
Transformation Charge	868,413	kw	$ 0.500	$ 5,210,476	868,413	$ 0.50	$ 5,210,476	$ -	0%
Up to 200 kW Subtotal				$ 41,227,973			$ 57,213,043	$ 15,985,070	39%

Illinois Power Company
Delivery Service Detailed Billing Determinants - Rebuttal
Twelve Months Ending 12-31-00

Class	Monthly Billing Units		Present Unit Charge	Present Annual Revenue	Monthly Billing Units	Proposed Unit Charge	Proposed Annual Revenue	Difference $ - Present v. Proposed	Percent Change
200 - 1000 kW									
Facilities Charge									
Three Phase									
<2.4 kV	751		$ 65.65	$ 591,638	751	$ 63.96	$ 576,408		
2.4-12.47 kV	94		$ 280.14	$ 315,998	94	$ 187.11	$ 211,060		
34.5-69 kV	15		$ 660.54	$ 118,897	15	$ 570.32	$ 102,658		
138 kV	1		$ 1,786.62	$ 21,439	1	$ 1,890.63	$ 22,688		
Subtotal	861	cust		$ 1,047,972	861		$ 912,813	$ (135,160)	-13%
Meter Charge									
Three Phase									
<2.4 kV	751		$ 34.35	$ 309,562	751	$ 17.94	$ 161,675		
2.4-12.47 kV	94		$ 94.86	$ 107,002	94	$ 148.15	$ 167,113		
34.5-69 kV	15		$ 99.46	$ 17,903	15	$ 354.43	$ 63,797		
138 kV	1		$ 113.38	$ 1,361	1	$ 1,392.79	$ 16,713		
Subtotal	861			$ 435,828	861		$ 409,299	$ (26,528)	-6%
Distribution Capacity Charge <= 12.47 kV	372,980	kw	N/A	$ -	372,980	$ 2.165	$ 9,690,025	$ 9,690,025	#DIV/0!
Demand Charge (per Monthly Max)									
<12.47 kV	284,127	kw	$ 2.136	$ 7,282,736	284,127	$ 0.4880	$ 1,663,846		
34.5-69 kV	53,009	kw	$ 0.263	$ 167,296	53,009	$ 0.4740	$ 301,515		
138 kV	504	kw	$ 0.016	$ 97	504	$ 0.0260	$ 157		
Subtotal	337,640	kw		$ 7,450,130	337,640		$ 1,965,519	$ (5,484,611)	-74%
Transformation Charge	390,884	kw	$ 0.500	$ 2,345,304	390,884	$ 0.50	$ 2,345,304	$ -	0%
200 - 1000 kW Subtotal				$ 11,279,233			$ 15,322,960	$ 4,043,726	36%
1000 kW and Over									
Facilities Charge									
Three Phase									
<2.4 kV	50		$ 65.65	$ 39,390	50	$ 63.96	$ 38,376		
2.4-12.47 kV	91		$ 280.14	$ 305,913	91	$ 187.11	$ 204,324		
34.5-69 kV	71		$ 660.54	$ 562,780	71	$ 570.32	$ 485,913		
138 kV	10		$ 1,786.62	$ 214,394	10	$ 1,890.63	$ 226,876		
Subtotal	222			$ 1,122,477	222		$ 955,488	$ (166,989)	-15%
Meter Charge									
Three Phase									
<2.4 kV	50		$ 34.35	$ 20,610	50	$ 17.94	$ 10,764		
2.4-12.47 kV	91		$ 94.86	$ 103,587	91	$ 148.15	$ 161,780		
34.5-69 kV	71		$ 99.46	$ 84,740	71	$ 354.43	$ 301,974		
138 kV	10		$ 113.38	$ 13,606	10	$ 1,392.79	$ 167,135		
Subtotal	222			$ 222,543	222		$ 641,653	$ 419,110	188%
Distribution Capacity Charge <= 12.47 kV	205,322	kw	N/A	$ -	201,182	$ 1.833	$ 4,425,199	$ 4,425,199	
Demand Charge (Monthly Max)									
<=12.47 kV	167,015	kw	$1.948	$ 3,904,143	163,185	$ 0.413	$ 808,745		
34.5-69 kV	932,032	kw	$0.239	$ 2,673,068	844,450	$ 0.401	$ 4,063,493		
138 kV	481,037	kw	$0.015	$ 86,587	206,195	$ 0.022	$ 54,435		
Subtotal	1,580,084	kw		$ 6,663,797	1,213,830		$ 4,926,674	$ (1,737,123)	-26%
Standby Capacity Requirement									
Distribution Capacity <=12.47 kV					4,140	$ 1.833	$ 91,056		
<=12.47 kV					3,870	$ 0.413	$ 19,178		
34.5-69 kV					98,876	$ 0.401	$ 475,792		
138 kV					277,206	$ 0.022	$ 73,182		
Subtotal							$ 659,209	$ 659,209	
Transformation Charge, Under 3 MW	118,159	kw	$ 0.500	$ 708,956	118,159	$ 0.500	$ 708,956	$ -	0%
Transformation Charge, Over 3 MW	75,899	kw	$ 0.750	$ 683,089	75,899	$ 0.750	$ 683,089	$ -	0%
Reactive Demand Charge	755,889	kVAR	$ 0.100	$ 907,067	755,889	$ 0.200	$ 1,814,134	$ 907,067	100%
1000 kW and Over Subtotal				$ 10,307,928			$ 14,814,401	$ 4,506,473	44%
PPO Calculator Fee	41.7		**$ -**	**$ -**	41.7	$ 3.50	$ 1,750		
Partial Requirements Admin Fee	1		$ -	$ -	1	$ 100.00	$ 1,200		
Demand Metered Total				**$ 62,815,135**			**$ 87,353,354**	$ 24,538,219	39%
Lighting (see pages 3-6)									
Lighting Total				**$ 20,612,284**	(Present excludes Residential)		**$ 20,541,325**	$ (70,958)	
GRAND TOTAL				**$ 90,536,954**			**$ 294,773,061**		

ILLINOIS POWER COMPANY
DELIVERY SERVICES - BILLING DETERMINANT ADJUSTMENTS
TWELVE MONTHS ENDING 12-31-00

CLASS		Original Customer Counts		Updated Customer Counts 08-31-01		Rebuttal Customer Counts	
		Customers	% of Total	Customers	% of Total	Customers	% of Total
Residential							
Facilities Charge							
Multi-Family		97,199	19.29%	97,199	19.29%	97,819	19.29%
Single Phase		388,467	77.11%	388,467	77.11%	390,942	77.11%
Three Phase		18,115	3.60%	18,115	3.60%	18,231	3.60%
	Subtotal	**503,782**	**100.00%**	**503,782**	**100.00%**	**506,992**	**100.00%**
Small Use General Service							
Metered							
Facilities Charge							
Single Phase		25,339	39.78%	26,622	41.79%	26,703	41.79%
Three Phase		7,977	12.52%	8,382	13.16%	8,408	13.16%
	Subtotal	**33,316**	**52.30%**	**35,005**	**54.95%**	**35,111**	**54.95%**
Demand Metered General Service							
Up to 200 kW							
Facilities Charge							
Single Phase		11,924	18.72%	11,237	17.64%	11,271	17.64%
Three Phase							
<2.4 kV		17,283	27.13%	16,288	25.57%	16,338	25.57%
2.4-12.47 kV		90	0.14%	85	0.13%	86	0.13%
34.5-69 kV		7	0.01%	7	0.01%	7	0.01%
138 kV		-	0.00%	-	0.00%	-	0.00%
	Subtotal	**29,305**	**46.00%**	**27,617**	**43.35%**	**27,702**	**43.35%**
200 - 1000 kW							
Facilities Charge							
Three Phase							
<2.4 kV		748	1.17%	748	1.17%	751	1.18%
2.4-12.47 kV		94	0.15%	94	0.15%	94	0.15%
34.5-69 kV		15	0.02%	15	0.02%	15	0.02%
138 kV		1	0.00%	1	0.00%	1	0.00%
	Subtotal	**859**	**1.35%**	**859**	**1.35%**	**861**	**1.35%**
1000 kW and Over							
Facilities Charge							
Three Phase							
<2.4 kV		50	0.08%	50	0.08%	50	0.08%
2.4-12.47 kV		91	0.14%	91	0.14%	91	0.14%
34.5-69 kV		71	0.11%	71	0.11%	71	0.11%
138 kV		10	0.02%	10	0.02%	10	0.02%
	Subtotal	**223**	**0.35%**	**223**	**0.35%**	**223**	**0.35%**
TOTAL RESIDENTIAL		**503,782**		**503,782**		**506,992**	
TOTAL NON-RESIDENTIAL		**63,703**		**63,703**		**63,897**	
GRAND TOTAL		**567,485**		**567,486**		**570,889**	

Illinois Power Company

DELIVERY SERVICES - BILLING DETERMINANT ADJUSTMENTS

Customer Counts & kWh Sales

Residential

	2000 Average Customers	2001 Forecasted Customers	Difference	1/2 Difference	Average Customer Bills per Month	% Change
Residential Customers	503,782	510,201	6,419	3,210	506,992	0.64%

	2000 Annual Sales	Annual Average use per Customer	Annual Average Use * 1/2 Difference	Adjusted Sales	Change in Sales kWh	% Change
Residential Sales	5,182,189,734	10,287	33,014,752	5,215,204,486	33,014,752	0.64%

Non-Residential

	2000 Average Customers	2001 Forecasted Customers	Difference	1/2 Difference	Average Customer Bills per Month	% Change
Non-Residential Customers	63,703	64,088	385	193	63,897	0.30%

	2000 Annual Sales	Annual Average use per Customer	Annual Average Use * 1/2 Difference	Adjusted Sales	Change in Sales kWh	% Change
Non-Residential Sales	13,980,065,442	219,457	42,245,461	14,022,310,903	42,245,461	0.30%

Customer Allocation % to Small Use General Servic	54.95%
Customer Allocation % to Demand Metered General Service	45.05%
Revised Small Use General Service Customers	35,111
Revised Demand Metered General Service Customers	28,785
Total Non-Residential Customers	63,897
kWh Allocation % to Small Use General Service	2.03%
kWh Allocation % to Demand Metered General Service	97.20%
kWh Allocation % to Lighting	0.77%
Revised Small Use General Service kWh Sales	284,462,453
Revised Demand Metered General Service kWh Sales	13,629,856,598
Revised Lighting kWh Sales	107,991,851
Total Non-Residential Sales	14,022,310,903

Illinois Power Company

DELIVERY SERVICES - BILLING DETERMINANT ADJUSTMENTS

Monthly Max Demand & Distribution Capacity After Adjustment for Rate 10 Qualifiers

Up to 200 kW

	Current Distribution Cap (kW)	Current Avgerage Distribution Cap (kW)	Increase in Customers	Proposed Distribution Capacity (kW)	Change in Distribution Capacity (kW)
Distribution Capacity <=12.47 kV	1,094,485	40	85	1,097,854	3,369

Demand Charge (Monthly Max)	Current Demand (kW)	Current Average Demand per Cutomer (kW)	Increase in Customers	Proposed Demand (kW)	Change in Demand (kW)
<= 12.47 kV	776,020	28	85	778,409	2,389
34.5 - 69 kV	12,122	1,732	0	12,122	0
138 kV	0	0	0	0	0
Subtotal	788,142			790,531	2,389

200-1000 kW

	Current Distribution Cap (kW)	Current Avgerage Distribution Cap (kW)	Increase in Customers	Proposed Distribution Capacity (kW)	Change in Distribution Capacity (kW)
Distribution Capacity <=12.47 kV	371,656	441	3	372,980	1,324

Demand Charge (Monthly Max)	Current Demand (kW)	Current Average Demand per Cutomer (kW)	Increase in Customers	Proposed Demand (kW)	Change in Demand (kW)
<= 12.47 kV	283,118	336	3	284,127	1,009
34.5 - 69 kV	53,009	3,534	0	53,009	0
138 kV	504	504	0	504	0
Subtotal	336,631			337,640	1,009

Illinois Power Company

Annualized Billing Determinants

Transformation Units After Adjustment for Rate 10 Qualifiers

Up to 200 kW

	Current Billing Units (kW)	Average Billing Units per Customer (kW)	Increase in Customers	Proposed Billing Units (kW)	Change in Billing Units (kW)
Transformation Charge	865,748	31	85	868,413	2,665

200-1000 kW

	Current Billing Units (kW)	Average Billing Units per Customer (kW)	Increase in Customers	Proposed Billing Units (kW)	Change in Billing Units (kW)
Transformation Charge	389,522	454	3	390,884	1,362

Illinois Power Company
Delivery Service Docket 01-0432
Rate Design Methodology

I. SUMMARY

This report documents the methods used to design the unit rate charges proposed in the rebuttal phase of the Illinois Power Company (IP) delivery service rate case, Docket 01-0432. The rate design methods aim to set rates that (1) will recover the total revenue requirement and (2) comply with the Customer Choice Law provisions requiring delivery service rates to be cost-based and to consider voltage level differences. In most cases (e.g., meters for Small Use General Service), the method uses a "top down" approach, in which an embedded cost of service is determined for a functional cost within a class of customers. In a few cases, (e.g., the calculation of prices for Transformation and Reactive Demand), the method uses a "bottom up" approach, in which the price was developed based on the replacement cost of providing the service. In still other cases (e.g., meter replacement costs were used to apportion meter costs among demand metered customers), the method uses replacement costs as a means to allocate the revenue requirement apportioned to a class of customers for a particular function. The specific uses of these methodologies are described in detail below.

II. SUPPORTING SCHEDULES

Supporting information for the rate design process is provided in the attached Schedules No. 1 – 3.

Components of the Embedded Cost of Service Study (ECOSS) supporting the rate design process are shown in Schedule 1.

The step-by-step process for design of the various charges is shown in Schedule 2. The specific information shown in this attachment is as follows:

- Facilities Charge Rate Design (Schedule 2, Item 1, Pages 1-5)
- Meters Charge Rate Design (Schedule 2, Item 2, Pages 1-4)
- Demand Charge Rate Design (Schedule 2, Item 3, Pages 1-7)
- Transformation Charge Rate Design (Schedule 2, Item 4, Page 1)
- Reactive Demand Charge Rate Design (Schedule 2, Item 5, Page 1)

Details of the methods followed for development of each of these rate components are provided below in the Methodology explanation.

III. REVENUE ALLOCATION AND CUSTOMER SEGMENTATION

As noted above, the rate design methods aim to recover Illinois Power's revenue requirement to provide delivery service. To develop these methods, IP divided the delivery service customers into four groups. These groups are:

- Residential
- Small Use General Service (smaller non-residential)
- Demand Metered General Service customers (larger non-residential)
- Lighting

The revenue requirement was allocated to each of these customer groups based on each group's cost contribution to the revenue requirement, as identified in the ECOSS.

To better reflect the applicable cost of service, these groups were segmented into sub-groups based on customer load size and the voltage levels at which service is taken.

The segmentation of the delivery service customers for allocation of revenue requirement to be recovered and for purposes of rate design is shown below:

Revenue Allocation	Rate Design
Residential	Residential
Small Use General Service (Non-residential, non-demand metered)	Small Use General Service • Metered Unmetered
Demand Metered General Service (Non-residential)	Demand Metered General Service • Up to 200 kW • 200 to 1,000 kW • Over 1,000 kW
Lighting	Area Lighting (by bulb type) • Residential • Non-residential Street Lighting (by bulb type)

This segmentation was done for rate design because Residential and Small Use General Service customers are typically served from secondary voltage levels and are metered with a watt-hour meter. Demand Metered General Service customers can be served at secondary, primary, subtransmission, or transmission voltage levels, and the facilities serve all customers too large to qualify for Small Use General Service. The rates for Demand Metered General Service customers recover the different costs incurred to serve at the various voltage levels. Lighting rates were designed based primarily on the cost of the local facilities required to provide the service, and recover the allocated revenue requirement for the class.

IV. METHODOLOGY

IP developed methods to determine appropriate (1) Facility Charges (Schedule 2, Item 1, Pages 1-5); (2) Meter Charges (Schedule 2, Item 2, Pages 1-4); (3)

Demand/Delivery Charges (Schedule 2, Item 3, Pages 1-7); (4) Transformation Charges (Schedule 2, Item 4, Page 1); and (5) Reactive Demand charges (Schedule 2, Item 5, Page 1). The first two charges are customer-related and were designed to recover the identified cost of the service lines, meters, similar equipment and expenses associated with each of these components required to serve the specified rate design customer. The last three charges were designed to recover the cost to serve the load requirements of each customer group. IP also developed (6) Reactive Demand Charges and (7) Lighting Rate Charges. The methods used to determine all of these charges are described in detail below.

A. <u>FACILITIES CHARGES</u>

The Facilities Charge rates were designed to recover the cost of current and potential meter transformers, service lines, and other related expenses (such as billing, call center, etc.) required to provide delivery service. These rates were designed for all customer segments. IP used the following process to calculate the Facilities Charges rates:

1. Calculation of the monthly cost per customer for current potential meter transformers (CT's & PT's) (Schedule 2, Item 1, Page 1):

First, IP allocated the embedded cost of these meters (Schedule 2) to the applicable customer groups based on the marginal cost of the meters. Since CT & PT meters are typically not installed for secondary voltage service, the marginal cost at this voltage is zero. For the purposes of rate design, IP used marginal values to allocate the residual revenue requirement for customers taking secondary voltage service and to mitigate increases for primary, subtransmission, and high voltage subtransmission demand metered customers (col 6). Second, IP multiplied the marginal cost by an annual carrying charge (col 7) to determine an annual carrying cost per unit (col 8). Third, IP multiplied the annual carrying cost per unit (col 8) by the number of customers (col 5) to determine the total annual carrying cost (col 9). Fourth, IP used this figure to determine the marginal cost allocation factor (col 10). Fifth, IP multiplied the marginal cost allocation factor (col 10) by each class' ECOS unbundled facilities cost (col 11) to determine the allocated unbundled cost per customer (col 12). Sixth, IP divided the unbundled Facilities cost per customer (col 12) by the number of customers (col 5) to determine the annual facilities cost per customer (col 13). Seventh, IP divided this same figure by 12 and arrived at a monthly facilities cost per customer (col 14).

2. Calculation of the Monthly Service Cost per customer (Schedule 2, Item 1, Page 2):

IP allocated the embedded cost of this service (Schedule 1) to the applicable customer groups based on the installed service cost following the same methodology as described for "current and potential transformers" (Item 1 above).

3. Calculation of the weighted monthly Other Expenses cost per customer (Schedule 2, Item 1, Page 3):

IP allocated the embedded cost of these expenses (Schedule 1) using weightings assigned to the customer groups. The detailed methodology and calculations are shown on Schedule 2, Item 1, Page 3.

4. Calculation of the Annual Total Facilities Unit Cost (CT & PT Meter, Service, and Other Expenses) (Schedule 2, Item 1, Page 4):

   Schedule 2, Item 1, page 4 summarizes the costs determined on pages 1-3 and multiplies the total cost (col 9), first, by the number of customers (col 5) and, second, by 12 to determine the annual cost based revenue for Facilities (col 10).

5. The Total Facilities Unit Cost was adjusted in rebuttal to account for rate design objectives other than strict cost recovery (Schedule 2, Item 1, Page 5):

   For Residential customers, IP adjusted the facilities cost to equal the cost of SC 2 bundled rates, which will go into effect on 5/01/2002. Non-residential facilities costs were adjusted by 50% of the difference between existing delivery service facilities charges and the calculated facilities cost. The remaining costs that resulted from deviating from cost of service were recovered in Delivery or Demand Charges.

B. <u>METER CHARGES</u>

The Meter Charges were designed to recover the unbundled cost per customer of providing meter service, meter reading, and meter-related collectibles. These rates were designed for Small Use General Service and Demand Metered General

Service customers, and rates have also been calculated for residential customers.

IP used the following process to calculate the Meter Charges:

1. Calculation of the monthly Unbundled Meter cost per customer (Schedule 2, Item 2, Page 1):

   First, IP allocated the embedded cost of these meters (Schedule 1) to the applicable customer groups based on the marginal cost of the meters (col 6). Second, IP multiplied the marginal cost by an annual carrying charge (col 7) to determine an annual carrying cost per unit (col 8). Third, IP multiplied the annual carrying cost per unit (col 8) by the number of customers (col 5) to determine the total annual carrying cost (col 9). Fourth, IP used this figure to determine the marginal cost allocation factor (col 10). Fifth, IP multiplied the marginal cost allocation factor (col 10) by each class' ECOS unbundled meter cost (col 11) to determine the allocated unbundled meter cost (col 12). Sixth, IP divided the unbundled meter cost (col 12) by the number of customers (col 5) to determine the annual meter cost per customer (col 13). Finally, IP divided the annual meter cost per customer by 12 to determine the monthly meter cost per customer (col 14).

2. Calculation of the weighted monthly Meter Reading Expenses cost per customer (Schedule 2, Item 2, Page 2):

   IP allocated the embedded cost of Meter Reading (Schedule 1) via weightings assigned to the customer groups. The detailed methodology and calculations are shown on Schedule 2, Item 2, page 2.

3. Calculation of the weighed monthly Meter Reading Uncollectible cost per customer (Schedule 2, Item 2, Page 3):

   IP allocated the embedded cost of this expense (Schedule 1) via weightings assigned to the customer groups. The detailed methodology and calculations are shown on Schedule 2, Item 2, Page 3.

4. Calculation of the Total Meter Cost (Meter, Meter Reading, and Meter Reading Uncollectible Costs) (Schedule 2, Item 2, Page 4):

   IP did not unbundle the meter cost for Residential customers for delivery service, even though an IP schedule shows an unbundled rate. IP made no adjustments to the unbundled meter cost in developing the Metering Charges.

C. <u>DEMAND/DELIVERY CHARGES</u>

Demand/Delivery Charges were designed to recover embedded Demand costs (Schedule 1). IP designed delivery rates for Residential and Small Use General Service customers based on per kWh charges. IP developed demand rates, including Standby Capacity charges and Distribution Capacity charges, for Demand Metered General Service customers. IP used the following process to calculate the demand rates for Demand Metered General Service customers:

<u>Demand Charge Development</u>

1. Allocation of demand cost offsets to the appropriate voltage level category (Schedule 2, Item 3, Page 1):

   First, the Company's demand related costs for the demand metered customers provided the starting point (Schedule 1) for determining the allocation of demand costs. Second, IP offset the demand cost by an amount equal to the Transformation Charge revenue contribution. The Transformation Charge was set independently, and, thus, it provided an offset for purposes of setting other demand charges. Third, miscellaneous revenue also provided a cost offset. As shown in Col (5), the Company identified a significant amount of miscellaneous revenue that could be directly allocated to respective voltage levels by identifying individual customers that contribute miscellaneous revenue at each voltage level. Fourth, the miscellaneous revenue that was not allocated to a specific voltage level was allocated to each voltage category based on the relative weighting of ECOS to total ECOS. Fifth, IP limited rate decreases for some Facilities Charges and produced a subsidy that was used to further reduce the demand costs to be recovered through demand charges. Finally, IP allocated the excess facilities revenue to each voltage level based on the relative weighting of ECOS to total ECOS.

2. Calculation of the Demand Charge for use of subtransmission system (34.5-69 kV) facilities (Schedule 2, Item 3, Page 2):

First, IP divided the ECOS for subtransmission level service by the loss factor adjusted demand of all customers that use the subtransmission system. The applicable loss factor contemplates only losses from subtransmission to primary voltage, because 1 MW served at primary must also contemplate use of the subtransmission system at 1 MW plus the loss factor. Then IP assigned the loss-factor-adjusted monthly unit cost to each voltage level of subtransmission service.

3. Calculation of the Demand Charge for use of high voltage subtransmission (138 kV and over) facilities (Schedule 2, Item 3, Page 3):

   First, IP divided the ECOS for high voltage subtransmission level service by the loss factor adjusted demand of all customers that use the subtransmission system. The applicable loss factors contemplate losses from high voltage subtransmission to subtransmission, and from high voltage subtransmission to primary voltage, because 1 MW served at voltages below high voltage subtransmission must also contemplate use of the high voltage subtransmission system at 1 MW plus a loss factor. Then, IP assigned the loss-factor-adjusted monthly unit cost to each voltage level of high voltage subtransmission service.

4. Determination of the total demand cost (Schedule 2, Item 3, Page 4), by totaling the subtransmission and high voltage subtransmission costs by voltage level.

5. Calculation of the distribution capacity charge based on customer category (Schedule 2, Item 3, Page 5):

   IP designed the distribution capacity charge to recover the cost of low voltage facilities, and thus the charge applies only to customers at 12.47 kV or below. Accordingly, no loss factor adjustments are necessary. IP used the Distribution Capacity as the demand billing determinant. The Distribution Capacity is the customer's maximum demand reached in the past 12 months. IP allocated a portion of the cost of the secondary system to customers below 200 kW. Thus, the Distribution Capacity Charge for customers below 200 kW also included costs for this portion of the secondary system and differentiated the charge from the charge for larger customers. Larger customers typically receive service from dedicated facilities connected to the primary (or higher) voltage system.

6. IP further adjusted the demand rates for larger customers (over 1,000 kW) to reflect the revenue contribution associated with separate pricing for reactive demand (Schedule 2, Item 3, Page 6). IP adjusted the rates designed in steps 1 – 5 above based on the percentage of the reactive demand revenue to total demand revenue at prices before the reactive demand adjustment. The calculation is limited to customers with demands over 1,000 kW.

<u>Delivery Charge Development</u>

The Delivery Charge applies to non-demand metered customers and was designed to recover the delivery service revenue requirement allocation that is not recovered in the Facilities and Meter (if any) Charges. IP used a two-block rate design structure to design delivery rates for Residential and Small Use General Service metered customers. These blocks were set at (1) the first 300 kWh per month, and (2) over 300 kWh per month. IP used the following processes to calculate these charges:

1. Calculation of the second block delivery charge (Schedule 2, Item 3, Page 7):

IP adjusted the embedded demand cost for miscellaneous cost, reduced it by the amount of embedded secondary demand cost (Schedule 1) and divided the resulting embedded demand cost by the total kWh billing determinant.

2. Calculation of the first block energy charge (Schedule 2, Item 3, Page 7):

   IP divided the embedded cost for secondary demand (Schedule 1) by the kWh billing determinant in the first block (less than 300 kWh per month) and added the block 2 energy charge.

3. Calculation of Non-Residential Small Use General Service Rates:

   IP calculated the rates for non-residential Small Use General Service customers for the Facilities Charge adjustment in a manner similar to that described for the Demand Metered General Service customers (Schedule 2, Item 3, Page 7):

   In addition, IP added an amount for a revenue deficiency caused by rounding facilities and meter costs to the facilities charge adjustment to arrive at the total adjustment. IP set the rates for Residential customers based on the recommendation of AG/CUB, which maintains the same first block premium as in SC 2 over the tail block charge.

4. Calculation of a Flat Delivery Rate for Unmetered Customers:

   IP designed a flat delivery rate for unmetered customers by dividing the total embedded demand cost for this customer group (Schedule 1) by the total deliveries (Schedule 2, Item 3, Page 7).

D. TRANSFORMATION CHARGES

Transformation charges for Demand Metered General Service customers were based on the marginal cost of overhead and underground transformer units. The current bundled transformation rate for customers less than 3 MW is $0.50 per kW, and the rate for those customer greater than 3 MW is $0.75 per kW. IP used these same rates in the design of cost recovery for delivery service. As indicated, IP used the marginal cost of transformer units for customers less than 3 MW to support the delivery service rate design (Schedule 2, Item 4, Page 1).

E. REACTIVE DEMAND

IP "price-unbundled" the Reactive Demand charge, applicable only to Demand Metered General Service customers greater than 1,000 kW, because these customers are large enough to economically install customer-owned capacitors. This charge is based on the installed cost of capacitors at various voltage levels (Schedule 2, Item 5, Page 1).

F. LIGHTING RATES

IP based the revenue target for the lighting class on the revenue requirement attributed to the Lighting class (Schedule 3, Item 5, Pages 1-4). First, IP adjusted individual non-residential bulb prices on a pro-rata basis to arrive at the total revenue requirement target. Second, IP developed residential bulb prices by starting with the bundled rate and adjusting for the additional 5% rate decrease to become effective on 5/01/2002. Third, IP removed the marginal cost of energy that was used to develop the prices for existing bundled service from each bulb price. This step made the basis for the existing non-residential and residential bulb prices consistent. Finally, IP further adjusted the residential bulb prices on the same pro-rata basis as the non-residential customers.

Illinois Power Company
Delivery Service
ECOSS Components
TME 12-31-00

Schedule 1

Source: ECOSS 10-09-01	Residential Cost	Small Commercial Metered	Small Commercial Unmetered	Total	General Service Up to 200 kW	General Service 200-1000 kW	General Service Over 1000 kW	General Service Total	Lighting	Total Company
Demand Components										
Demand Transmission	$ 2,418,848	$ 92,941	$ 8,900	$ 101,841	988,760.63	395,084.34	958,626.03	$ 2,342,471	$ 69,585	$ 4,932,745
Demand Subtransmission	$ 19,048,152	$ 732,059	$ 70,100	$ 802,159	$ 7,017,239	$ 2,804,249	$ 6,803,374	$ 16,624,862	$ 547,415	$ 37,022,588
Demand Primary	$ 84,681,000	$ 3,241,333	$ 314,333	$ 3,555,667	$ 31,211,000	$ 10,574,333	$ 4,465,000	$ 46,250,333	$ 2,441,667	$ 136,928,667
Demand Secondary	$ 15,450,000	$ 593,000	$ 57,333	$ 650,333	$ 5,701,000	$ -	$ -	$ 5,701,000	$ 443,667	$ 22,245,000
Demand Substation	$ 7,922,000	$ 305,000	$ 29,333	$ 334,333	$ 2,954,000	$ 1,183,333	$ 4,189,000	$ 8,326,333	$ 227,667	$ 16,810,333
Subtotal Demand Components	$ 129,520,000	$ 4,964,333	$ 480,000	$ 5,444,333	$ 47,872,000	$ 14,957,000	$ 16,416,000	$ 79,245,000	$ 3,730,000	$ 217,939,333
Customer Components										
Total Meter	$ 10,523,000	$ 1,110,000	$ -	$ 1,110,000	$ 4,937,000	$ 1,465,000	$ 4,375,000	$ 10,777,000	$ -	$ 22,410,000
Meter Reading	$ 10,679,000	$ 923,000	$ -	$ 923,000	$ 584,000	$ 19,000	$ 11,000	$ 614,000	$ -	$ 12,216,000
Other Expenses (Uncollectibles)	$ 21,582,000	$ 1,993,667	$ 102,000	$ 2,095,667	$ 1,293,000	$ 41,000	$ 20,000	$ 1,354,000	$ 16,282,000	$ 41,313,667
Services	$ 7,927,000	$ 666,000	$ 30,000	$ 696,000	$ 884,000	$ 109,000	$ 28,000	$ 1,021,000	$ 624,000	$ 10,268,000
Subtotal Customer Components	$ 50,711,000	$ 4,692,667	$ 132,000	$ 4,824,667	$ 7,698,000	$ 1,634,000	$ 4,434,000	$ 13,766,000	$ 16,906,000	$ 86,207,667
Miscellaneous	$ (2,738,000)	$ (797,000)	$ (88,000)	$ (885,000)	$ (1,343,000)	$ (637,000)	$ (3,679,000)	$ (5,659,000)	$ (92,000)	$ (9,374,000)
Total	$ 177,493,000	$ 8,860,000	$ 524,000	$ 9,384,000	$ 54,227,000	$ 15,954,000	$ 17,171,000	$ 87,352,000	$ 20,544,000	$ 294,773,000
Unbundled Metering										
Meters w/o CT & PT	$ 9,816,000	$ 1,034,000	$ -	$ 1,034,000	$ 3,982,000	$ 383,500	$ 619,000	$ 4,984,500	$ -	$ 15,834,500
Meter Reading Expense	$ 9,356,000	$ 809,000	$ -	$ 809,000	$ 512,000	$ 16,500	$ 9,000	$ 537,500	$ -	$ 10,702,500
Subtotal	$ 19,172,000	$ 1,843,000	$ -	$ 1,843,000	$ 4,494,000	$ 400,000	$ 628,000	$ 5,522,000	$ -	$ 26,537,000
Uncollectible	$ 81,000	$ 18,000	$ 1,000	$ 19,000	$ 13,000	$ 1,000	$ -	$ 14,000	$ -	$ 114,000
Total Unbundled Metering	$ 19,253,000	$ 1,861,000	$ 1,000	$ 1,862,000	$ 4,507,000	$ 401,000	$ 628,000	$ 5,536,000	$ -	$ 26,651,000
Total Meter - Unbundled Meter	$ 707,000	$ 76,000	$ -	$ 76,000	$ 955,000	$ 1,081,500	$ 3,756,000	$ 5,792,500	$ -	$ 6,575,500
Total Other - Unbundled Uncollectible	$ 21,501,000	$ 1,975,667	$ 101,000	$ 2,076,667	$ 1,280,000	$ 40,000	$ 20,000	$ 1,340,000	$ 16,282,000	$ 41,199,667
Total Meter Reading - Unbundled Meter Rd	$ 1,323,000	$ 114,000	$ -	$ 114,000	$ 72,000	$ 2,500	$ 2,000	$ 76,500	$ -	$ 1,513,500

Sources: ECOSS detailed reports provided by IP witness Althoff

Step 1: Calculate CT&PT Meter Cost

					Calculate CT&PT Cost Allocation Factor									Calculate Allocated Embedded Unbundled Facilities Cost			
Class	Service	Phase	Category	Customers	Marginal Cost of Current & Potential Transformers	1/	Annual Carrying Rate		Annual Carrying Cost per Unit		Total Annual Carrying Cost	Marginal Cost Allocation Factor		ECOS Unbundled CT&PT Facilities Cost	Allocated Unbundled CT&PT Facilities Cost	Annual CT&PT Facilities Cost per Customer	Monthly CT&PT Facilities Cost per Customer
(1)	(2)	(3)	(4)	(5)	(6)		(7)		(8)		(9)	(10)		(11)	(12)	(13)	(14)
Residential	Secondary	1	Multi-Family	97,819	**$ 10**	x	11.51%	=	$ 1.15	->	$ 112,589	19.29%			$ 136,408	$ 1.39	$ 0.12
	Secondary	1	Single Family	390,942	**$ 10**	x	11.51%	=	$ 1.15	->	$ 449,975	77.11%			$ 545,169	$ 1.39	$ 0.12
	Secondary	3	Single Family	18,231	**$ 10**	x	11.51%	=	$ 1.15	->	$ 20,984	3.60%			$ 25,423	$ 1.39	$ 0.12
				506,992							$ 583,547	100.00%		$ 707,000	$ 707,000		
Small Use General Service	Secondary	1		26,703	**$ 10**	x	11.51%	=	$ 1.15	->	$ 30,735	76.05%			$ 57,800	$ 2.16	$ 0.18
	Secondary	3		8,408	**$ 10**	x	11.51%	=	$ 1.15	->	$ 9,678	23.95%			$ 18,200	$ 2.16	$ 0.18
				35,111							$ 40,413	100.00%		$ 76,000	$ 76,000		
Demand Metered General Service	Secondary	1	0-200 kW	11,271	**$ 500**	x	11.51%	=	$ 57.55	->	$ 648,646	28.11%			$ 1,628,235	$ 144.46	$ 12.04
	Secondary	3	0-200 kW	16,338	**$ 500**	x	11.51%	=	$ 57.55	->	$ 940,252	40.75%			$ 2,360,225	$ 144.46	$ 12.04
	Secondary	3	Over 200 kW	801	**$ 500**	x	11.51%	=	$ 57.55	->	$ 46,098	2.00%			$ 115,714	$ 144.46	$ 12.04
	Primary	3	All sizes	271	$ 5,888	x	11.51%	=	$ 677.71	->	$ 183,659	7.96%			$ 461,022	$ 1,701.19	$ 141.77
	Subtransmission	3	All sizes	93	$ 29,691	x	11.51%	=	$ 3,417.43	->	$ 317,821	13.77%			$ 797,797	$ 8,578.46	$ 714.87
	Transmission	3	All sizes	11	$ 135,143	x	11.51%	=	$ 15,554.96	->	$ 171,105	7.41%			$ 429,507	$ 39,046.14	$ 3,253.84
				28,785							$ 2,307,581	100.00%		$ 5,792,500	$ 5,792,500		

Notes:
Col (5): From billing determinants, IP Exhibit 6.8.
Col (6): Primary, subtransmission, and high voltage subtransmission costs from engineering study. Secondary values based on judgement since current transformers & potential transformers are typically not installed for secondary voltage service, and the marginal cost of CT&PT's for these facilities is zero. The marginal values shown were put into place to allocate the residual revenue requirement for customers taking secondary voltage service and to mitigate increases for primary-high voltage subtransmission customers.
Col (7): Annual levelized carrying charge
Col (8): Col (7) x Col (6)
Col (9): Col (8) x Col (5)
Col (10): Col (9)/Subtotal Col (9)
Col (11): From Schedule 2. Represents customers cost difference between full ECOSS results and ECOSS results following the unbundled metering methodology. Provided by IP witness Althoff.
Col (12): Col (11) subtotal x Col (10)
Col (13): Col (12) / Col (5)
Col (14): Col (13) / 12 months

Step 2: Calculate Service Cost

					Calculate Service Cost Allocation Factor								Calculate Allocated Installed Service Cost			
Class	Service	Phase	Category	Customers	Installed Cost of Service Lines	1/	Annual Carrying Rate		Annual Carrying Cost per Unit		Total Annual Carrying Cost	Service Cost Allocation Factor	ECOS Service Cost	Allocated Service Cost	Annual Service Cost per Customer	Monthly Service Cost per Customer
(1)	(2)	(3)	(4)	(5)	(6)		(7)		(8)		(9)	(10)	(11)	(12)	(13)	(14)
Residential	Secondary	1	Multi-Family	97,819	$ 70	x	11.51%	=	$ 8.06	->	$ 788,124	5.57%		$ 441,508	$ 4.51	$ 0.38
	Secondary	1	Single Family	390,942	$ 279	x	11.51%	=	$ 32.11	->	$ 12,554,290	88.72%		$ 7,032,925	$ 17.99	$ 1.50
	Secondary	3	Single Family	18,231	$ 385	x	11.51%	=	$ 44.31	->	$ 807,867	5.71%		$ 452,568	$ 24.82	$ 2.07
				506,992							$ 14,150,281	100.00%	$ 7,927,000	$ 7,927,000		
Small Use General Service	Secondary	1		26,703	$ 279	x	11.51%	=	$ 32.11	->	$ 857,511	69.71%		$ 464,273	$ 17.39	$ 1.45
	Secondary	3		8,408	$ 385	x	11.51%	=	$ 44.31	->	$ 372,588	30.29%		$ 201,727	$ 23.99	$ 2.00
				35,111							$ 1,230,099	100.00%	$ 666,000	$ 666,000		
Demand Metered General Service	Secondary	1	0-200 kW	11,271	$ 366	x	11.51%	=	$ 42.13	->	$ 474,809	20.06%		$ 204,800	$ 18.17	$ 1.51
	Secondary	3	0-200 kW	16,338	$ 672	x	11.51%	=	$ 77.35	->	$ 1,263,699	53.39%		$ 545,072	$ 33.36	$ 2.78
	Secondary	3	Over 200 kW	801	$ 6,818	x	11.51%	=	$ 784.75	->	$ 628,586	26.56%		$ 271,128	$ 338.49	$ 28.21
	Primary	3	All sizes	271	$ -	x	11.51%	=	$ -	->	$ -	0.00%		$ -	$ -	$ -
	Subtransmission	3	All sizes	93	$ -	x	11.51%	=	$ -	->	$ -	0.00%		$ -	$ -	$ -
	Transmission	3	All sizes	11	$ -	x	11.51%	=	$ -	->	$ -	0.00%		$ -	$ -	$ -
				28,785							$ 2,367,094	100.00%	$ 1,021,000	$ 1,021,000		

Notes:
Col (5): From billing determinants, IP Exhibit 6.8.
Col (6): Service lines only classified as such at secondary voltage level. Thus, zero values for primary - high voltage subtransmission. Costs from engineering study.
Col (7): Annual levelized carrying charge
Col (8): Col (7) x Col (6)
Col (9): Col (8) x Col (5)
Col (10): Col (9)/Subtotal Col (9)
Col (11): From Schedule 2. Service line ECOSS results provided by IP witness Althoff.
Col (12): Col (11) subtotal x Col (10)
Col (13): Col (12) / Col (5)
Col (14): Col (13) / 12 months

Schedule 2, Item 1, Page 3

Step 3: Allocate Cost of Other Expenses (billing, call center, etc.)

				Calculate Customer Weighting			Calculate Weighted Average Cost of Other Expenses			
Class	Service	Phase	Category	Customers	Customer Weighting Factor	Weighted # Customers	ECOS Other Expenses Cost	Average Annual Cost per Customer	Average Monthly Cost per Customer	Weighted Monthly Cost per Customer
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Residential	Secondary	1	Multi-Family	97,819	1.00	97,819				$ 3.75
	Secondary	1	Single Family	390,942	1.00	390,942				$ 3.75
	Secondary	3	Single Family	18,231	1.00	18,231				$ 3.75
				506,992		506,992	$ 22,824,000	$ 45.02	$ 3.75	
Small Use General Service	Secondary	1		26,703	1.00	26,703				$ 4.96
	Secondary	3		8,408	1.00	8,408				$ 4.96
				35,111		35,111	$ 2,089,667	$ 59.52	$ 4.96	
Demand Metered General Service	Secondary	1	0-200 kW	11,271	1.00	11,271				$ 4.04
	Secondary	3	0-200 kW	16,338	1.00	16,338				$ 4.04
	Secondary	3	Over 200 kW	801	1.00	801				$ 4.04
	Primary	3	All sizes	271	1.00	271				$ 4.04
	Subtransmission	3	All sizes	93	5.00	465				$ 20.20
	Transmission	3	All sizes	11	5.00	55				$ 20.20
				28,785		29,201	$ 1,416,500	$ 48.51	$ 4.04	

Notes:
Col (5): From billing determinants, IP Exhibit 6.8.
Col (6): Based on values used in 1999 DST case and discussion with customer service personnel.
Col (7): Col (5) x Col (6)
Col (8): From Schedule 2. Represents "other expenses" less uncollectible expense allocated to unbundled metering. Provided by IP witness Althoff.
Col (9): Subtotal Col (8) / Subtotal Col (7)
Col (10): Col (9) / 12 months
Col (11): Subtotal Col (10) x Col (6)

Step 4: Determine Total Facilities Cost

Class	Service	Phase	Category	Customers	Monthly CT&PT Facilities Cost	Monthly Service Cost	Monthly Other Expense Cost	Total Monthly Facilities Unit Cost	Annual Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Residential	Secondary	1	Multi-Family	97,819	N/A	$ 0.38	$ 3.75	$ 4.13	$ 4,847,885
	Secondary	1	Single Family	390,942	N/A	$ 1.50	$ 3.75	$ 5.25	$ 24,629,364
	Secondary	3	Single Family	18,231	N/A	$ 2.07	$ 3.75	$ 5.82	$ 1,273,233
				506,992					$ 30,750,482
Small Use General Service	Secondary	1		26,703	N/A	$ 1.45	$ 4.96	$ 6.41	$ 2,053,636
	Secondary	3		8,408	N/A	$ 2.00	$ 4.96	$ 6.96	$ 702,171
				35,111					$ 2,755,807
Demand Metered General Service	Secondary	1	0-200 kW	11,271	$ 12.04	$ 1.51	$ 4.04	$ 17.59	$ 2,379,452
	Secondary	3	0-200 kW	16,338	$ 12.04	$ 2.78	$ 4.04	$ 18.86	$ 3,697,363
	Secondary	3	Over 200 kW	801	$ 12.04	$ 28.21	$ 4.04	$ 44.29	$ 425,675
	Primary	3	All sizes	271	$ 141.77	$ -	$ 4.04	$ 145.81	$ 474,160
	Subtransmission	3	All sizes	93	$ 714.87	$ -	$ 20.20	$ 735.07	$ 820,340
	Transmission	3	All sizes	11	$ 3,253.84	$ -	$ 20.20	$ 3,274.04	$ 432,174
				28,785					$ 8,229,164

Notes:
Col (5): From billing determinants, IP Exhibit 6.8.
Col (6): From Schedule 2, Item 1, Page 1
Col (7): From Schedule 2, Item 1, Page 2
#REF!
Col (9): Col (6) + Col (7) + Col (8)
Col (10): Col (9) x Col (5) x 12 months

Step 5: Apply Adjustments for Rebuttal Filing

							ADJUSTMENT APPLIED FOR REBUTTAL							
Class	Service	Phase	Category	Customers	Total Monthly Facilities Unit Cost	Annual Revenue Based on Cost	Present Facilities & Meter Charge	Facilities & Meter Cost	Difference Present - Cost	Adjustment to Cost	Adjusted Facilities Price	Annual Revenue Based on Cost	Annual Revenue Based on Adjusted Price	Difference (Adjusted - Non-Adjusted)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Residential	Secondary	1	Multi-Family	97,819	$ 4.13	$ 4,847,885	$ 5.96	$ 7.13	N/A	N/A	$ 5.96	$ 8,368,185	$ 6,995,980	$ 1,372,205
	Secondary	1	Single Family	390,942	$ 5.25	$ 24,629,364	$ 7.96	$ 8.25	N/A	N/A	$ 7.96	$ 38,698,623	$ 37,342,806	$ 1,355,817
	Secondary	3	Single Family	18,231	$ 5.82	$ 1,273,233	$ 16.00	$ 13.34	N/A	N/A	$ 16.00	$ 2,917,692	$ 3,500,296	$ (582,604)
				506,992		$ 30,750,482						$ 49,984,501	$ 47,839,083	**$ 2,145,419**
Small Use General Service	Secondary	1		26,703	$ 6.41	$ 2,053,636	$ 13.00	$ 9.76	$ 3.24	$ 1.62	$ 8.03	$ 2,053,636	$ 2,572,438	$ (518,802)
	Secondary	3		8,408	$ 6.96	$ 702,171	$ 23.00	$ 14.74	$ 8.26	$ 4.13	$ 11.09	$ 702,171	$ 1,118,692	$ (416,521)
				35,111		$ 2,755,807						$ 2,755,807	$ 3,691,130	**$ (935,323)**
Demand Metered General Service	Secondary	1	0-200 kW	11,271	$ 17.59	$ 2,379,452	$ 41.25	$ 26.21	$ 15.04	$ 7.52	$ 25.11	$ 2,379,452	$ 3,396,390	$ (1,016,937)
	Secondary	3	0-200 kW	16,338	$ 18.86	$ 3,697,363	$ 51.00	$ 34.85	$ 16.15	$ 8.08	$ 26.93	$ 3,697,363	$ 5,280,645	$ (1,583,281)
	Secondary	3	Over 200 kW	801	$ 44.29	$ 425,675	$ 100.00	$ 62.22	$ 37.78	$ 18.89	$ 63.18	$ 425,675	$ 607,240	$ (181,565)
	Primary	3	All sizes	271	$ 145.81	$ 474,160	$ 375.00	$ 293.95	$ 81.05	$ 40.52	$ 186.33	$ 474,160	$ 605,946	$ (131,786)
	Subtransmission	3	All sizes	93	$ 735.07	$ 820,340	$ 760.00	$ 1,089.50	$ (329.50)	$ (164.75)	$ 570.32	$ 820,340	$ 636,479	$ 183,861
	Transmission	3	All sizes	11	$ 3,274.04	$ 432,174	$ 1,900.00	$ 4,666.83	$ (2,766.83)	$ (1,383.42)	$ 1,890.63	$ 432,174	$ 249,563	$ 182,611
				28,785		$ 8,229,164						$ 8,229,164	$ 10,776,262	**$ (2,547,098)**

Col (5): From billing determinants, IP Exhibit 6.8.
Col (5): From billing determinants, IP Exhibit 6.8.
#REF!
#REF!
Col (8): From bundled SC 2 (residential), and combination of existing metering and facilities charges for non-residential customers.
Col (9): Col (6) plus Schedule 2, Item 2, Page 4, Col (9)
Col (10): Col (8) - Col (9)
Col (11): Residential facilities charge set equal to current bundled rates. Non-residential facilities charges adjusted by 50% of the difference between current Facility and Meter charges and current Facilities and Meter cost.
Col (12): Col (6) + Col (11)
Col (13): For residential, Col (5) x Col (9) x 12 months. For non-residential, equal to Col (7), or Col (6) x Col (5) x 12 months.
Col (14): Col (5) x Col (12) x 12 months
Col (15): Col (13) - Col (14)

Step 1: Calculate Meter Cost

					Calculate Meter Cost Allocation Factor									Calculate Allocated Embedded Meter Cost			
Class	Service	Phase	Category	Customers	Marginal Meter Cost	1/	Annual Carrying Rate		Annual Carrying Cost per Unit		Total Annual Carrying Cost	Marginal Cost Allocation Factor		ECOS Meter Cost	Allocated Meter Cost	Annual Meter Cost per Customer	Monthly Meter Cost per Customer
(1)	(2)	(3)	(4)	(5)	(6)		(7)		(8)		(9)	(10)		(11)	(12)	(13)	(14)
Residential	Secondary	1	Multi-Family	97,819	$ 46	x	11.51%	=	$ 5.29	->	$ 517,910	17.37%			$ 1,704,668	$ 17.43	$ 1.45
	Secondary	1	Single Family	390,942	$ 46	x	11.51%	=	$ 5.29	->	$ 2,069,883	69.41%			$ 6,812,891	$ 17.43	$ 1.45
	Secondary	3	Single Family	18,231	$ 188	x	11.51%	=	$ 21.64	->	$ 394,491	13.23%			$ 1,298,441	$ 71.22	$ 5.94
				506,992							$ 2,982,284	100.00%		$ 9,816,000	$ 9,816,000	$ 19.36	$ 1.61
Small Use General Service	Secondary	1		26,703	$ 46	x	11.51%	=	$ 5.29	->	$ 141,382	43.73%			$ 452,148	$ 16.93	$ 1.41
	Secondary	3		8,408	$ 188	x	11.51%	=	$ 21.64	->	$ 181,939	56.27%			$ 581,852	$ 69.20	$ 5.77
				35,111							$ 323,321	100.00%		$ 1,034,000	$ 1,034,000	$ 29.45	$ 2.45
Demand Metered General Service	Secondary	1	0-200 kW	11,271	$ 226	x	11.51%	=	$ 26.01	->	$ 293,188	19.18%			$ 956,190	$ 84.84	$ 7.07
	Secondary	3	0-200 kW	16,338	$ 461	x	11.51%	=	$ 53.06	->	$ 866,912	56.72%			$ 2,827,307	$ 173.05	$ 14.42
	Secondary	3	Over 200 kW	801	$ 523	x	11.51%	=	$ 60.20	->	$ 48,218	3.15%			$ 157,256	$ 196.32	$ 16.36
	Primary	3	All sizes	271	$ 4,674	x	11.51%	=	$ 537.98	->	$ 145,792	9.54%			$ 475,479	$ 1,754.53	$ 146.21
	Subtransmission	3	All sizes	93	$ 11,055	x	11.51%	=	$ 1,272.43	->	$ 118,336	7.74%			$ 385,936	$ 4,149.85	$ 345.82
	Transmission	3	All sizes	11	$ 44,157	x	11.51%	=	$ 5,082.47	->	$ 55,907	3.66%			$ 182,333	$ 16,575.73	$ 1,381.31
				28,785							$ 1,528,353	100.00%		$ 4,984,500	$ 4,984,500	$ 173.16	$ 14.43

Notes:
Col (5): From billing determinants, IP Exhibit 6.8.
Col (6): Meter costs without CT&PT's from engineering study.
Col (7): Annual levelized carrying charge
Col (8): Col (7) x Col (6)
Col (9): Col (8) x Col (5)
Col (10): Col (9)/Subtotal Col (9)
Col (11): From Schedule 2. Represents ECOSS of unbundled metering. Provided by IP witness Althoff.
Col (12): Col (11) subtotal x Col (10)
Col (13): Col (12) / Col (5)
Col (14): Col (13) / 12 months

Step 2: Allocate Cost of Meter Reading Expenses

				Calculate Customer Weighting			Calculate Weighted Average Cost of Meter Reading Expenses			
Class	Service	Phase	Category	Customers	Customer Weighting Factor	Weighted # Customers	ECOS Meter Reading Expenses	Average Annual Cost per Customer	Average Monthly Cost per Customer	Weighted Monthly Cost per Customer
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Residential	Secondary	1	Multi-Family	97,819	1.00	97,819				$ 1.54
	Secondary	1	Single Family	390,942	1.00	390,942				$ 1.54
	Secondary	3	Single Family	18,231	1.00	18,231				$ 1.54
				506,992		506,992	$ 9,356,000	$ 18.45	$ 1.54	
Small Use General Service	Secondary	1		26,703	1.00	26,703				$ 1.92
	Secondary	3		8,408	1.00	8,408				$ 1.92
				35,111		35,111	$ 809,000	$ 23.04	$ 1.92	
Demand Metered General Service	Secondary	1	0-200 kW	11,271	1.00	11,271				$ 1.53
	Secondary	3	0-200 kW	16,338	1.00	16,338				$ 1.53
	Secondary	3	Over 200 kW	801	1.00	801				$ 1.53
	Primary	3	All sizes	271	1.00	271				$ 1.53
	Subtransmission	3	All sizes	93	5.00	465				$ 7.65
	Transmission	3	All sizes	11	5.00	55				$ 7.65
				28,785		29,201	$ 537,500	$ 18.41	$ 1.53	

Notes:
Col (5): From billing determinants, IP Exhibit 6.8.
Col (6): Based on values used in 1999 DST case and discussion with customer service personnel.
Col (7): Col (5) x Col (6)
Col (8): From Schedule 2. Meter reading expense from unbundled metering ECOS study. Provided by IP witness Althoff.
Col (9): Subtotal Col (8) / Subtotal Col (7)
Col (10): Col (9) / 12 months
Col (11): Subtotal Col (10) x Col (6)

Schedule 2, Item 2, Page 3

Step 3: Allocate Cost of Meter Related Uncollectible Expenses

				Calculate Customer Weighting			Calculate Weighted Average Cost of Other Expenses			
Class	Service	Phase	Category	Customers	Customer Weighting Factor	Weighted # Customers	ECOS Other Expenses Cost	Average Annual Cost per Customer	Average Monthly Cost per Customer	Weighted Monthly Cost per Customer
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Residential	Secondary	1	Multi-Family	97,819	0.90	88,097				$ 0.01
	Secondary	1	Single Family	390,942	0.90	352,091				$ 0.01
	Secondary	3	Single Family	18,231	3.69	67,261				$ 0.04
				506,992		507,449	$ 81,000	$ 0.16	$ 0.01	
Small Use General Service	Secondary	1		26,703	0.58	15,368				$ 0.02
	Secondary	3		8,408	2.36	19,802				$ 0.09
				35,111		35,170	$ 18,000	$ 0.51	$ 0.04	
Demand Metered General Service	Secondary	1	0-200 kW	11,271	0.49	5,522				$ 0.02
	Secondary	3	0-200 kW	16,338	1.00	16,327				$ 0.04
	Secondary	3	Over 200 kW	801	1.13	908				$ 0.05
	Primary	3	All sizes	271	10.13	2,746				$ 0.41
	Subtransmission	3	All sizes	93	23.97	2,229				$ 0.96
	Transmission	3	All sizes	11	95.72	1,053				$ 3.83
				28,785		28,785	$ 14,000	$ 0.49	$ 0.04	

Notes:
Col (5): From billing determinants, IP Exhibit 6.8.
Col (6): Based on unbundled meter cost per customer type / average meter cost per customer for group as shown on Schedule 3, Item 2, Page 1, Col (14).
Col (7): Col (5) x Col (6)
Col (8): From Schedule 2. Unbundled metering expense for uncollectibles from unbundled metering ECOS study. Provided by IP witness Althoff.
Col (9): Subtotal Col (8) / Subtotal Col (7)
Col (10): Col (9) / 12 months
Col (11): Subtotal Col (10) x Col (6)

Step 4: Determine Total Meter Cost

Class	Service	Phase	Category	Customers	Monthly Meter Cost	Monthly Meter Reading Cost	Monthly Meter Uncollectible Cost	Total Monthly Meter Charges	Annual Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Residential	Secondary	1	Multi-Family	97,819	$ 1.45	$ 1.54	$ 0.01	$ 3.00	$ 3,520,300
	Secondary	1	Single Family	390,942	$ 1.45	$ 1.54	$ 0.01	$ 3.00	$ 14,069,260
	Secondary	3	Single Family	18,231	$ 5.94	$ 1.54	$ 0.04	$ 7.52	$ 1,644,460
				506,992					$ 19,234,020
Small Use General Service	Secondary	1		26,703	$ 1.41	$ 1.92	$ 0.02	$ 3.35	$ 1,074,428
	Secondary	3		8,408	$ 5.77	$ 1.92	$ 0.09	$ 7.78	$ 785,395
				35,111					$ 1,859,824
Demand Metered General Service	Secondary	1	0-200 kW	11,271	$ 7.07	$ 1.53	$ 0.02	$ 8.62	$ 1,165,818
	Secondary	3	0-200 kW	16,338	$ 14.42	$ 1.53	$ 0.04	$ 15.99	$ 3,134,930
	Secondary	3	Over 200 kW	801	$ 16.36	$ 1.53	$ 0.05	$ 17.94	$ 172,395
	Primary	3	All sizes	271	$ 146.21	$ 1.53	$ 0.41	$ 148.15	$ 481,768
	Subtransmission	3	All sizes	93	$ 345.82	$ 7.65	$ 0.96	$ 354.43	$ 395,542
	Transmission	3	All sizes	11	$ 1,381.31	$ 7.65	$ 3.83	$ 1,392.79	$ 183,848
				28,785					$ 5,534,301

Notes:
Col (5): From billing determinants, IP Exhibit 6.8.
Col (6): From Schedule 2, Item 2, Page 1, Col (14)
Col (7): From Schedule 2, Item 2, Page 2, Col (11)
Col (8): From Schedule 2, Item 2, Page 3, Col (11)
Col (9): Col (6) + Col (7) + Col (8)
Col (10): Col (9) x Col (5) x 12 months

Step 1: Allocate Demand Cost Offsets To Voltage Level Category

			Miscellaneous Revenue Offset								
Voltage Level Category	ECOS Demand Cost	Transformation Revenue Offset	Total Miscellaneous Revenue	Directly Assignable Misc Rev	Total Miscellaneous - Directly Assignable	ECOS Demand Cost as % of Total ECOS Demand	Allocation of Residual Miscellaneous Cost	Total Miscellaneous Revenue Assignment	Facilities Charge Adjustment	Facilities Charge Adj as % of Total Demand ECOS	Adjusted ECOS Demand
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Secondary	$ 5,701,000	$ -		$ -		7.19%	$ 66,250	$ 66,250		$ 183,242	$ 5,451,508
Primary	$ 54,576,667	$ 7,803,543		$ 829,020		68.87%	$ 634,221	$ 1,463,241		$ 1,754,206	$ 43,555,676
Subtransmission	$ 16,624,862	$ 1,122,277		$ 2,547,457		20.98%	$ 193,193	$ 2,740,650		$ 534,357	$ 12,227,578
High Voltage Subtransmission	$ 2,342,471	$ 22,004		$ 1,361,638		2.96%	$ 27,221	$ 1,388,859		$ 75,292	$ 856,316
	$ 79,245,000	$ 8,947,824	$ 5,659,000	$ 4,738,115	$ 920,885	100.00%	$ 920,885	$ 5,659,000	$ 2,547,098	$ 2,547,098	$ 62,091,079

Notes:
Col (1): Secondary only applies to customers below 200 kW
Col (2): From Schedule 2
Col (3): Total from billing determinants. Allocated by voltage using CIS data of Transformation Capacity by supply voltage.
Col (4): From Schedule 2
Col (5): Based on CIS data of customer rental revenue by supply voltage
Col (6): Col (4) - Col (5)
Col (7): Col (2) / Total Col (2)
Col (8): Col (7) x Total Col (6)
Col (9): Col (8) + Col (5)
Col (10): From Schedule 2, Item 1, Page 5 x Total Col (15)
Col (11): Col (7) x Total Col (10)

Step 2: Calculate Subtransmission Demand Charge

Voltage Level	Demand	ECOS Demand Cost	Monthly Unit Cost	Loss Factor (Subtransmission to Primary)	Loss Factor Adjusted Demand	Loss Factor Adjusted Monthly Unit Cost	Allocated Loss Factor Adjusted Monthly Unit Cost	Annual Demand Rate Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
< 12.47 kV	1,225,721			1.02769	1,259,662		$ 0.461	$ 6,780,687
Standby < 12.47 kV	3,870			1.02769	3,977		$ 0.461	$ 21,407
34.5 - 69 kV	909,581			1.00000	909,581		$ 0.448	$ 4,889,907
Standby 34.5 - 69 kV	98,876			1.00000	98,876		$ 0.448	$ 531,558
	2,238,048	$ 12,227,578	$ 0.455		2,272,096	$ 0.448		$ 12,223,560

Notes:

Col (2): From billing determinants, IP Exhibit 6.8. Sum of demand metered customers' monthly maximum demands at the Subtransmission voltage level.

Col (3): From Schedule 2, Item 3, Page 1, Col (12)

Col (4): Col (3) / Col (2)

Col (5): Average loss factor from subtransmission (4.511%) to primary (1.695%) voltage.

Col (6): Col (2) x Col (5)

Col (7): Total Col (3) / Total Col (6) / 12 months

Col (8): Total Col (7) x Col (5)

Col (9): Col (2) x Col (8) x 12 months

Step 3: Calculate High Voltage Subtransmission Demand Charge

Voltage Level	Demand	ECOS Demand Cost	Monthly Unit Cost	Loss Factor (Transmission to Subtransmission)	Adjusted Demand	Adjusted Monthly Unit Cost	Allocated Unit Cost	Annual Revenue @ Cost
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
< 12.47 kV	1,225,721			1.04511	1,281,013		0.0270	$ 397,134
Standby < 12.47 kV	3,870			1.04511	4,044		0.0270	$ 1,254
34.5 - 69 kV	909,581			1.01695	924,998		0.0260	$ 283,789
Standby 34.5 - 69 kV	98,876			1.01695	100,552		0.0260	$ 30,849
138 kV	206,699			1.00000	206,699		0.0260	$ 64,490
Standby 138 kV	277,206			1.00000	277,206		0.0260	$ 86,488
	2,721,952	$ 856,316	$ 0.02622		2,794,512	$ 0.02554		$ 864,004

Notes:
Col (2): From billing determinants, IP Exhibit 6.8. Sum of demand metered customers' monthly maximum demands at the high voltage Subtransmission voltage level.
Col (3): From Schedule 2, Item 3, Page 1, Col (12)
Col (4): Col (3) / Col (2)
Col (5): Average loss factor from transmission to subtransmission (1.695%)and from transmissoin to primary (4.511%) voltages.
Col (6): Col (2) x Col (5)
Col (7): Total Col (3) / Total Col (6) / 12 months
Col (8): Total Col (7) x Col (5)
Col (9): Col (2) x Col (8) x 12 months

Step 4: Calculate Total Unit Rate for Demand Charges

Voltage Level	Demand	Subtransmission Level Unit Cost	High Voltage Subtransmission Level Unit Cost	Total Unit Cost	Annual Revenue @ Cost
(1)	(2)	(3)	(4)	(5)	(6)
< 12.47 kV	1,225,721	$ 0.4610	$ 0.0270	$ 0.48800	$ 7,177,821
Standby < 12.47 kV	3,870	$ 0.4610	$ 0.0270	$ 0.48800	$ 22,661
34.5 - 69 kV	909,581	$ 0.4480	$ 0.0260	$ 0.47400	$ 5,173,697
Standby 34.5 - 69 kV	98,876	$ 0.4480	$ 0.0260	$ 0.47400	$ 562,408
138 kV	206,699	$ -	$ 0.0260	$ 0.02600	$ 64,490
Standby 138 kV	277,206	$ -	$ 0.0260	$ 0.02600	$ 86,488
	2,721,952				$ 13,087,564

Col (2): From billing determinants, IP Exhibit 6.8. Sum of demand metered customers' monthly maximum demands at the Subtransmission voltage level.
Col (3): From Schedule 2, Item 3, Page 2, Col (8)
Col (4): From Schedule 2, Item 3, Page 3, Col (8)
Col (5): Col (3) + Col (4)
Col (6): Col (2) x Col (5) x 12 months

Step 5: Calculate Distribution Capacity Charge

Customer Category	Distribution Capacity	ECOS Demand Cost	Monthly Unit Cost	Revenue at Cost	Unit Cost by Service Level
(1)	(2)	(3)	(4)	(5)	(6)
Secondary					
< 200 kW	1,097,854	$ 5,451,508	$ 0.41	$ 5,451,508	$ 0.414
Primary					
< 200 kW	1,097,854			$ 28,522,259	$ 2.165
200-1000 kW	372,980			$ 9,690,025	$ 2.165
> 1000 kW	201,182			$ 5,226,708	$ 2.165
Standby	4,140			$ 107,549	$ 2.165
	1,676,156	$ 43,555,676	$ 2.165	$ 48,998,050	
Total by Demand Category					
< 200 kW					$ 2.579
200-1000 kW					$ 2.165
> 1000 kW					$ 2.165

Col (2): From billing determinants, IP Exhibit 6.8. Sum of demand metered customers' monthly maximum demands at the Primary voltage leve
Col (3): From Schedule 2, Item 3, Page 1, Col (12). Sum of Primary and Secondary.
Col (4): Col (3) / Col (2) / 12 months
Col (5): Total Col (4) x Col (2) / 12 months
Col (6): Col (5) / Col (2) / 12 months

Step 6: Adjust Demand Price for Large Customers Due to Reactive Demand Contribution

Voltage Level (Over 1000 kW)	Demand	Unit Cost Before RD Adjustment	Revenue Before RD Adjustment	$/kVar	kVar Revenue/ Demand Revenue Before Adj	Unit Cost after RD Adjustment	Revenue After RD Adjustment	Total
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Primary Distribution Capacity	201,182	$ 2.1650	$ 5,226,708			1.8330	$ 4,425,199	
Standby Distribution Capacity	4,140	$ 2.1650	$ 107,549			1.8330	$ 91,056	
<=12.47	163,185	$ 0.4880	$ 955,611			0.4130	$ 808,745	
Standby<=12.47	3,870	$ 0.4880	$ 22,661			0.4130	$ 19,178	
34.5-69	844,450	$ 0.4740	$ 4,803,232			0.4010	$ 4,063,493	
Standby 34.5-69	98,876	$ 0.4740	$ 562,408			0.4010	$ 475,792	
138	206,195	$ 0.0260	$ 64,333			0.0220	$ 54,435	
Standby 138	277,206	$ 0.0260	$ 86,488			0.0220	$ 73,182	
			$ 11,828,990	$ 1,814,134	15.34%		$ 10,011,082	$ 11,825,215

Col (2): From billing determinants, IP Exhibit 6.8. Values from customers over 1 MW.
Col (3): From Schedule 2, Item 3, Page 4, Col (5), and Schedule 2, Item 3, Page 5, Col (6)
Col (4): Col (3) x Col (2) x 12 months
Col (5): Total revenue generated by Reactive Demand Charge, shown in billing determinants, IP Exhibit 6.8
Col (6): Total Col (5) / Total Col (4)
Col (7): (1- Col (6)) x Col (3)
Col (8): Col (7) x Col (2) x 12 months
Col (9): Col (8) + Col (5)

Delivery Charge Calculation

Class	Block 2 Energy Charge						Block 1 Delivery Charge			
Class	ECOS Total Demand Cost	ECOS Miscellaneous Revenue	ECOS Secondary Demand Cost	Cost Basis for Tail Block	Total kWh	Block 2 Energy Charge	ECOS Secondary Demand Cost	Block 1 kWh	Block 1 Delivery Adder	Block 1 Delivery Charge
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Residential	$ 129,520,000	$ (2,738,000)	$ 15,450,000	$ 111,332,000	5,215,204,486	$ 0.02135	$ 15,450,000	1,728,869,694	$ 0.00894	$ 0.03029
Small Use General Service										
Metered	$ 4,964,333	$ (797,000)	$ 593,000	$ 3,574,333	249,629,495	$ 0.01432	$ 593,000	90,815,210	$ 0.00653	$ 0.02085
Unmetered	$ 480,000	$ (88,000)	$ -	$ 392,000	34,832,958	$ 0.01125	N/A	N/A	N/A	N/A

Class	Rebuttal Adjustment						Revenue Comparison		
Class	Facilities Adjustment ($)	Other Revenue Defeciency	Total Adjustment for Delivery	Delivery Charge Change Needed for Target (¢/kWh)	Adjusted Block 2 Delivery Charge	Adjusted Block 1 Delivery Charge	Annual Revenue @ Cost	Annual Revenue w/Facilities Adjustment	Difference
	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
Residential	$ 2,145,419	$ 726,499	$ 2,871,917	$ 0.00055	$ 0.02190	$ 0.03084	$ 126,792,277	$ 129,669,073	$ 2,876,796
Small Use General Service									
Metered	$ (935,323)	$ 77,036	$ (858,286)	$ (0.00344)	$ 0.01088	$ 0.01741	$ 4,167,488	$ 3,308,992	$ (858,496)
Unmetered									

Col (2): From Schedule 2
Col (3): From Schedule 2
Col (4): From Schedule 2
Col (5): Col (2) + Col (3) - Col (4)
Col (6): From billing determinants, IP Exhibit 6.8
Col (7): Col (5) / Col (6)
Col (8): From Schedule 2. Same as Col (4)
Col (9): From billing determinants, IP Exhibit 6.8
Col (10): Col (8) / Col (9)
Col (11): Col (10) + Col (7)
'Col (12): Schedule 2, Item 1, Page 5
Col (13): Revenue deficiency caused by rounding of facilities and meter costs
Col (14): Col (12) + Col (13)
Col (15): Col (14) / Col (6)
Col (16): Col (15) + Col (7)
Col (17): Col (15) + Col (11)
Col (18): Col (7) x tail block energy (Col 6 - Col 9) + Col (11) x Col (9)
Col (19): Col (16) x tail block energy (Col 6 - Col 9) + Col (17) x Col (9)
Col (20): Col (19) - Col (18)
Note: The Company will use the rate design proposed by AG/CUB for the Residential Class.

Customer Class	Phase	kW	Overhead/ Underground	Total Cost	Weighting OH & UG	Weighted Cost	Annual Carrying Charge	Annual Carrying Cost	Monthly Carrying Cost	Cost per kW	O&M & A&G per kW	Total
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Demand Metered General Svc, Up to 200 kW	1	41	OH	$ 1,400	82.86%							
Demand Metered General Svc, Up to 200 kW	1	41	UG	$ 2,383	17.14%	$ 1,568	11.51%	$ 181	$ 15.04	$ 0.42	$ 0.16	$ 0.58
Demand Metered General Svc, Up to 200 kW	1	82	OH	$ 1,821	82.86%							
Demand Metered General Svc, Up to 200 kW	1	82	UG	$ 2,673	17.14%	$ 1,967	11.51%	$ 226	$ 18.87	$ 0.27	$ 0.16	$ 0.42
Demand Metered General Svc, Up to 200 kW	3	283	OH	$ 8,524	100.00%	$ 8,524	11.51%	$ 981	$ 81.76	$ 0.33	$ 0.16	$ 0.49
Demand Metered General Svc, 200-1,000 kW	3	848	Either	$ 16,349	81.45%							
Demand Metered General Svc, Over 1,000 kW	3	2,120	Either	$ 38,842	18.55%	$ 20,521	11.51%	$ 2,362	$ 196.83	$ 0.21	$ 0.16	$ 0.37
											AVERAGE TOTAL COST PER KW - <3,000 MW	**$ 0.47**
											ROUNDED TO NEAREST MULTIPLE	**0.5000**
				Representative Sample of Recently Constructed Substations for Customers Over 3mW								
Demand Metered General Svc, Over 3 mW	3	3,188		$ 130,809			11.51%	15,056	$ 1,255	$ 0.45	$ 0.16	$ 0.61
Demand Metered General Svc, Over 3 mW	3	2,975		$ 219,686			11.51%	25,286	$ 2,107	$ 0.81	$ 0.16	$ 0.97
Demand Metered General Svc, Over 3 mW	3	4,463		$ 116,516			11.51%	13,411	$ 1,118	$ 0.29	$ 0.16	$ 0.45
Demand Metered General Svc, Over 3 mW	3	6,375		$ 156,132			11.51%	17,971	$ 1,498	$ 0.27	$ 0.16	$ 0.43
Demand Metered General Svc, Over 3 mW	3	5,950		$ 66,425			11.51%	7,646	$ 637	$ 0.12	$ 0.16	$ 0.28

Notes:
Col (3): Maximum kW rating for transformer
Col (5): For smaller facilities, from engineering study of replacement cost to install facilities. For larger facilities, based on work order totals.
Col (6): Overhead vs undergound weighting based on querry of transformer data base
Col (7): Col (5) x Col (6)
Col (8): Distribution equipment levelized carrying charge
Col (9): Col (7) x Col (8)
Col (10): Col (9) / 12 months
Col (11): (Col (10) x 1.15 reserve margin) / Col (3)
Col (12): Average cost of O&M and A&G for transformation facilities in test year.
Col (13): Col (11) + Col (12)

Capacitor	**kVAR**	**Total Cost**	**Weighting Fixed & Switched**	**Weighted Cost**	**Annual Carrying Charge**	**Annual Carrying Cost**	**Monthly Carrying Cost**	**Cost per kVAR**	**O&M & A&G per kVAR**	**Total**
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Primary Voltage Facilities										
300 kVAR, Fixed	300	$ 4,025	28.60%							
300 kVAR, Switched	300	$ 7,705	71.40%	$ 6,653	11.51%	$ 766	$ 64	$ 0.245	$ 0.065	$ 0.310
450 kVAR, Fixed	450	$ 4,173	28.60%							
450 kVAR, Switched	450	$ 7,694	71.40%	$ 6,687	11.51%	$ 770	$ 64	$ 0.164	$ 0.065	$ 0.229
600 kVAR, Fixed	600	$ 4,407	28.60%							
600 kVAR, Switched	600	$ 7,913	71.40%	$ 6,910	11.51%	$ 795	$ 66	$ 0.127	$ 0.065	$ 0.192
900 kVAR, Fixed	900	$ 4,746	28.60%							
900 kVAR, Switched	900	$ 8,375	71.40%	$ 7,337	11.51%	$ 844	$ 70	$ 0.090	$ 0.065	$ 0.155
									AVERAGE TOTAL COST PER kVAR	$ 0.221
									ROUNDED TO NEAREST MULTIPLE	0.2000
Subtransmission Voltage Facilities										
34.5 kV, 10.8mVAR	10,800	$ 280,229			11.51%	32,254	$ 2,688	$ 0.286	$ 0.065	$ 0.351
34.5 kV, 7.2mVAR	7,200	$ 198,919			11.51%	22,896	$ 1,908	$ 0.305	$ 0.065	$ 0.370
69 kV, 10.8 mVAR	10,800	$ 271,013			11.51%	31,194	$ 2,599	$ 0.277	$ 0.065	$ 0.342
34.5 kV, 6000 kVAR	6,300	$ 91,578			11.51%	10,541	$ 878	$ 0.160	$ 0.065	$ 0.225

Notes:
Col (2): Peak kVAR for capacitor
Col (3): For smaller facilities, from engineering study of replacement cost to install facilities. For larger facilities, based on work order totals from recently constructed facilities.
Col (4): Fixed vs switched weighting based on querry of capacitor data base
Col (5): Col (3) x Col (4)
Col (6): Distribution equipment levelized carrying charge
Col (7): Col (5) x Col (6)
Col (8): Col (7) / 12 months
Col (9): (Col (8) x 1.15 reserve margin) / Col (2)
Col (10): Average cost of O&M and A&G for capacitor facilities in test year.
Col (11): Col (9) + Col (10)

Schedule 3, Item 1, Page 1

Lighting Category	ECOS Revenue Requirement	Annual Revenues At Prices Proposed in Direct	Difference	Rate Adjustment Factor
Residential Outdoor Lights		$ 1,833,759		
Non-Residential Outdoor Lights		$ 5,121,167		
Municipal Street Lights		$ 15,491,116		
TOTAL	$ 20,544,000	$ 22,446,043	$ (1,902,043)	**-8.47%**

Schedule 3, Item 1, Page 2

Residential Outdoor Area Lighting Service Rate Design

Area Lighting	Lumens	# Lamps	Monthly Price per Lamp Proposed in Direct	Total Annual Revenue @ Prices in Direct	Adjusted Delivery Service Monthly Price per Lamp	Adjusted Delivery Service Total Annual Revenue
Incandescent						
	2,500*	133	$ 6.86	$ 10,949	$ 6.28	$ 10,023
	4,000*	30	$ 7.23	$ 2,603	$ 6.62	$ 2,383
	6,000*	19	$ 7.63	$ 1,740	$ 6.98	$ 1,591
	10,000*	2	$ 8.57	$ 206	$ 7.84	$ 188
Mercury Vapor						
	6,400	19,486	$ 4.20	$ 982,094	$ 3.84	$ 897,915
	9,400	5,149	$ 4.64	$ 286,696	$ 4.25	$ 262,599
	16,000	228	$ 6.45	$ 17,647	$ 5.90	$ 16,142
	45,200	1	$ 11.81	$ 142	$ 10.81	$ 130
Sodium Vapor						
	8,500	2,888	$ 4.85	$ 168,082	$ 4.44	$ 153,873
	15,000	4,451	$ 5.05	$ 269,731	$ 4.62	$ 246,763
	22,000	270	$ 6.35	$ 20,574	$ 5.81	$ 18,824
	45,000	191	$ 7.37	$ 16,892	$ 6.75	$ 15,471
Metal Halide						
	24,600**	5	$ 11.91	$ 715	$ 10.90	$ 654
Directional Lighting						
Mercury Vapor						
	16,000*	38	$ 7.65	$ 3,488	$ 7.00	$ 3,192
	45,200*	5	$ 10.77	$ 646	$ 9.86	$ 592
Sodium Vapor						
	22,000	118	$ 9.11	$ 12,900	$ 8.34	$ 11,809
	45,000	197	$ 8.97	$ 21,205	$ 8.21	$ 19,408
Metal Halide						
	24,600	82	$ 8.03	$ 7,902	$ 7.35	$ 7,232
	83,000	56	$ 14.21	$ 9,549	$ 13.01	$ 8,743
TOTAL		33,349		$ 1,833,759		$ 1,677,534

* Lamps not available to new installations

** Lamp available in rectangular cutoff luminaire only

Non-residential Outdoor Area Lighting Service Rate Design

Area Lighting	Lumens	# Lamps	Monthly Price per Lamp Proposed in Direct	Total Annual Revenue @ Prices in Direct	Adjusted Delivery Service Monthly Price per Lamp	Adjusted Delivery Service Total Annual Revenue
Incandescent						
	2,500*	59	$ 8.88	$ 6,287	$ 8.13	$ 5,756
	4,000 *	16	$ 9.52	$ 1,828	$ 8.71	$ 1,672
	6,000 *	16	$ 10.19	$ 1,956	$ 9.33	$ 1,791
	10,000 *	4	$ 11.73	$ 563	$ 10.74	$ 516
Mercury Vapor						
	6,400 *	6,219	$ 5.56	$ 414,932	$ 5.09	$ 379,857
	9,400 *	4,371	$ 6.22	$ 326,251	$ 5.69	$ 298,452
	16,000 *	3,203	$ 8.70	$ 334,393	$ 7.96	$ 305,951
	45,200 *	588	$ 16.39	$ 115,648	$ 15.00	$ 105,840
Sodium Vapor						
	8,500	1,376	$ 6.24	$ 103,035	$ 5.71	$ 94,284
	15,000	6,012	$ 6.56	$ 473,265	$ 6.00	$ 432,864
	22,000	3,337	$ 8.38	$ 335,569	$ 7.67	$ 307,137
	45,000	5,134	$ 9.88	$ 608,687	$ 9.04	$ 556,936
Metal Halide						
	24,600**	88	$ 15.56	$ 16,431	$ 14.24	$ 15,037
Directional Lighting						
Mercury Vapor						
	16,000 Lumen*	676	$ 10.20	$ 82,742	$ 9.34	$ 75,766
	45,200 Lumen*	633	$ 15.09	$ 114,624	$ 13.81	$ 104,901
Sodium Vapor						
	22,000 Lumen	1,460	$ 11.83	$ 207,262	$ 10.83	$ 189,742
	45,000 Lumen	6,240	$ 11.88	$ 889,574	$ 10.87	$ 813,946
Metal Halide						
	24,600 Lumen	1,797	$ 10.71	$ 230,950	$ 9.80	$ 211,327
	83,000 Lumen	3,682	$ 19.40	$ 857,170	$ 17.76	$ 784,708
TOTAL		44,911		$ 5,121,167		$ 4,686,482

* Lamps not available to new installations

** Lamp available in rectangular cutoff luminaire only

Street Lighting (Municipal) Service Rate Design

		Lumens	# Lamps	Monthly Price per Lamp Proposed in Direct	Total Annual Revenue @ Prices in Direct	Adjusted Delivery Service Monthly Price per Lamp	Adjusted Delivery Service Total Annual Revenue
Incandescent							
	A						
		1,000 *	47	$ 11.58	$ 6,531	$ 10.60	$ 5,978
		2,500 *	507	$ 11.83	$ 71,974	$ 10.83	$ 65,890
		4,000 *	2,034	$ 12.37	$ 301,927	$ 11.32	$ 276,299
		6,000 *	820	$ 12.69	$ 124,870	$ 11.61	$ 114,242
		10,000 *	1	$ 14.08	$ 169	$ 12.89	$ 155
	B						
		4,000 *	41	$ 22.92	$ 11,277	$ 20.98	$ 10,322
		6,000 *	26	$ 23.19	$ 7,235	$ 21.22	$ 6,621
	C						
		1,000 *	42	$ 3.08	$ 1,552	$ 2.82	$ 1,421
		2,500 *	129	$ 3.38	$ 5,232	$ 3.09	$ 4,783
		4,000 *	32	$ 3.72	$ 1,428	$ 3.40	$ 1,306
		6,000 *	42	$ 4.09	$ 2,061	$ 3.74	$ 1,885
Mercury Vapor						$ -	
	A						
		7,200	36,553	$ 10.26	$ 4,500,405	$ 9.39	$ 4,118,792
		11,000	5,294	$ 10.72	$ 681,020	$ 9.81	$ 623,210
		17,000	6,566	$ 13.40	$ 1,055,813	$ 12.26	$ 965,990
		30,000 *	41	$ 18.08	$ 8,895	$ 16.55	$ 8,143
		46,000 *	250	$ 19.69	$ 59,070	$ 18.02	$ 54,060
	B						
		7,200	1,442	$ 20.96	$ 362,692	$ 19.18	$ 331,891
		11,000	232	$ 21.32	$ 59,355	$ 19.51	$ 54,316
		17,000	3,246	$ 23.25	$ 905,634	$ 21.28	$ 828,899
		30,000 *	106	$ 27.68	$ 35,209	$ 25.33	$ 32,220
		46,000 *	214	$ 29.04	$ 74,575	$ 26.58	$ 68,257
	C						
		7,200	125	$ 1.71	$ 2,565	$ 1.57	$ 2,355
		17,000	36	$ 3.05	$ 1,318	$ 2.79	$ 1,205
		46,000 *	41	$ 5.34	$ 2,627	$ 4.89	$ 2,406
Sodium Vapor							
	A						
		8,700	12,789	$ 10.74	$ 1,648,246	$ 9.83	$ 1,508,590
		15,000	12,463	$ 12.86	$ 1,923,290	$ 11.77	$ 1,760,274
		23,000	7,642	$ 14.13	$ 1,295,778	$ 12.93	$ 1,185,733
		46,500	2,780	$ 16.18	$ 539,765	$ 14.81	$ 494,062
	B						
		8,700	1,023	$ 21.39	$ 262,584	$ 19.58	$ 240,364
		15,000	1,126	$ 23.51	$ 317,667	$ 21.52	$ 290,778
		23,000	2,244	$ 25.93	$ 698,243	$ 23.73	$ 639,001
		46,500	1,550	$ 26.43	$ 491,598	$ 24.19	$ 449,934
	C						
		8,700	69	$ 1.89	$ 1,565	$ 1.73	$ 1,432
		15,000	125	$ 2.76	$ 4,140	$ 2.53	$ 3,795
		23,000	166	$ 4.93	$ 9,821	$ 4.51	$ 8,984
		46,500	27	$ 7.63	$ 2,472	$ 6.98	$ 2,262
		130,200*	8	$ 23.65	$ 2,270	$ 21.65	$ 2,078
Metal Halide							
	C						
		9,600	111	$ 7.69	$ 10,243	$ 7.04	$ 9,377
TOTAL			99,990		$ 15,491,116		$ 14,177,310

* Lamps not available to new installations

Illinois Power Company
Current and Proposed Unit Charges for Delivery Service
Non-Lighting Rates

Residential

Facilities Charge	Current	Proposed
Multi-family Service	N/A	$ 5.96
Single-phase Service	N/A	$ 7.96
Three-phase Service	N/A	$ 16.00

Delivery Charge	Current	Proposed
1st 300 kWh per month	N/A	$ 0.03422
Over 300 kWh per month	N/A	$ 0.02022

Small Use General Service

Facilities Charge	Current	Proposed
Single-phase Service	$ 9.53	$ 8.03
Three-phase Service	$ 19.53	$ 11.09
Unmetered Service	$ 8.50	$ 8.50

Meter Charge	Current	Proposed
Single-phase Service	$ 3.47	$ 3.35
Three-phase Service	$ 3.47	$ 7.78

Delivery Charge	Current	Proposed
1st 300 kWh per month	$ 0.00140	$ 0.01741
Over 300 kWh per month	$ 0.00140	$ 0.01088
All Unmetered use	$ 0.00140	$ 0.00859

Demand Metered General Service

Facilities Charge	Current	Proposed
Single-phase Service, all voltages	$ 35.79	$ 25.11
3-phase, under 2.4kV and 200 kW	$ 35.32	$ 26.93
3-phase, under 2.4kV, over 200 kW	$ 65.65	$ 63.96
3-phase, 2.4kV to 12.49 kV	$ 280.14	$ 187.11
3-phase, 34.5 kV and 69 kV	$ 660.54	$ 570.32
3-phase, 138 kV	$ 1,786.62	$ 1,890.63

Meter Charge	Current	Proposed
Single-phase Service, all voltages	$ 5.46	$ 8.62
3-phase, under 2.4kV and 200 kW	$ 15.68	$ 15.99
3-phase, under 2.4kV, over 200 kW	$ 34.35	$ 17.94
3-phase, 2.4kV to 12.49 kV	$ 94.86	$ 148.15
3-phase, 34.5 kV and 69 kV	$ 99.46	$ 354.43
3-phase, 138 kV	$ 113.38	$ 1,392.79

Transformation Charge	Current	Proposed
Applicable to customers under 3,000 kW	$ 0.50	$ 0.50
Applicable to customers 3,000 kW & up	$ 0.75	$ 0.75

Distribution Capacity Charge	Current	Proposed
Distribution Capacity under 200 kW		
Supply Line 12.49 kV and Below	N/A	$ 2.579
Distribution Capacity under 1,000 kW		
Supply Line 12.49 kV and Below	N/A	$ 2.165
Distribution Capacity 1,000 kW and over		
Supply Line 12.49 kV and Below	N/A	$ 1.833
Demand Charge (Supply Line Voltage)	Current	Proposed
Distribution Capacity under 1,000 kW		
12.49 kV and Below	$ 2.136	$ 0.488
34.5kV and 69kV	$ 0.263	$ 0.474
138kV	$ 0.016	$ 0.026
Distribution Capacity 1,000 kW and over		
12.49 kV and Below	$ 1.948	$ 0.413
34.5kV and 69kV	$ 0.239	$ 0.401
138kV	$ 0.015	$ 0.022

Reactive Demand Charge	Current	Proposed
Applicable to customers 1,000 kW and ove	$ 0.1000	$ 0.2000

Illinois Power Company

Current and Proposed Unit Charges for Delivery Service

Lighting Rates

Outdoor Area Lighting Service

		Residential		Non-Residential	
Type of Lamp	Lumen Rating	Current	Proposed	Current	Proposed
Area Lighting					
Incandescent	2,500 Lumen*	N/A	$ 6.28	$ 8.88	$ 8.13
	4,000 Lumen*	N/A	$ 6.62	$ 9.52	$ 8.71
	6,000 Lumen*	N/A	$ 6.98	$ 10.19	$ 9.33
	10,000 Lumen*	N/A	$ 7.84	$ 11.73	$ 10.74
Mercury Vapor	6,400 Lumen	N/A	$ 3.84	$ 5.56	$ 5.09
	9,400 Lumen	N/A	$ 4.25	$ 6.22	$ 5.69
	16,000 Lumen	N/A	$ 5.90	$ 8.70	$ 7.96
	45,200 Lumen	N/A	$ 10.81	$ 16.39	$ 15.00
Sodium Vapor	8,500 Lumen	N/A	$ 4.44	$ 6.24	$ 5.71
	15,000 Lumen	N/A	$ 4.62	$ 6.56	$ 6.00
	22,000 Lumen	N/A	$ 5.81	$ 8.38	$ 7.67
	45,000 Lumen	N/A	$ 6.75	$ 9.88	$ 9.04
Metal Halide	24,600 Lumen**	N/A	$ 10.90	$ 15.56	$ 14.24
		$ 187.11			
Directional Lighting					
Mercury Vapor	16,000 Lumen*	N/A	$ 7.00	$ 10.20	$ 9.34
	45,200 Lumen*	N/A	$ 9.86	$ 15.09	$ 13.81
Sodium Vapor	22,000 Lumen	N/A	$ 8.34	$ 11.83	$ 10.83
	45,000 Lumen	N/A	$ 8.21	$ 11.88	$ 10.87
Metal Halide	24,600 Lumen	N/A	$ 7.35	$ 10.71	$ 9.80
	83,000 Lumen	N/A	$ 13.01	$ 19.40	$ 17.76

* Lamps not available to new installations
** Lamp available in rectangular cutoff luminaire only

Municipal Street Lighting Service

		Class A		Class B		Class C	
Type of Lamp	Lumen Rating	Current	Proposed	Current	Proposed	Current	Proposed
Incandescent	1,000 Lumen*	$ 11.58	$ 10.60	$ -	$ -	$ 3.08	$ 2.82
	2,500 Lumen*	$ 11.83	$ 10.83	$ 22.43	$ 20.53	$ 3.38	$ 3.09
	4,000 Lumen*	$ 12.37	$ 11.32	$ 22.92	$ 20.98	$ 3.72	$ 3.40
	6,000 Lumen*	$ 12.69	$ 11.61	$ 23.19	$ 21.22	$ 4.09	$ 3.74
	10,000 Lumen*	$ 14.08	$ 12.89	$ 24.28	$ 22.22	$ -	$ -
Mercury Vapor	7,200 Lumen	$ 10.26	$ 9.39	$ 20.96	$ 19.18	$ 1.71	$ 1.57
	11,000 Lumen	$ 10.72	$ 9.81	$ 21.32	$ 19.51	$ 2.22	$ 2.03
	17,000 Lumen	$ 13.40	$ 12.26	$ 23.25	$ 21.28	$ 3.05	$ 2.79
	30,000 Lumen*	$ 18.08	$ 16.55	$ 27.68	$ 25.33	$ 4.33	$ 3.96
	46,000 Lumen*	$ 19.69	$ 18.02	$ 29.04	$ 26.58	$ 5.34	$ 4.89
Sodium Vapor	8,700 Lumen	$ 10.74	$ 9.83	$ 21.39	$ 19.58	$ 1.89	$ 1.73
	15,000 Lumen	$ 12.86	$ 11.77	$ 23.51	$ 21.52	$ 2.76	$ 2.53
	23,000 Lumen	$ 14.13	$ 12.93	$ 25.93	$ 23.73	$ 4.93	$ 4.51
	46,500 Lumen	$ 16.18	$ 14.81	$ 26.43	$ 24.19	$ 7.63	$ 6.98
	130,200 Lumen*	$ -	$ -	$ -	$ -	$ 23.65	$ 21.65
Metal Halide	9,600 Lumen	$ -	$ -	$ -	$ -	$ 7.69	$ 7.04

* Lamps not available to new installations

IP Exhibit 6.12

Secondary Facilities for Hypothetical System

	Circuit with Each Customer Sized At: 300 kWh - month	3,000 kWh - month
Transformer	$ 1,206	$ 1,616
Secondary Conductor	$ 500	$ 929
Service Lines	$ 1,005	$ 1,559
Total Cost	$ 2,711	$ 4,104
Customers in Hypothetical	6	6
Cost per Customer	$ 451.83	$ 684.00
Annual Carrying Charge	11.51%	11.51%
Annualized Cost	$ 52.01	$ 78.73
Annual kWh	3,600	36,000
Annual cost/kWh	$ 0.0144	$ 0.0022

Illinois Power Company
Distribution Capacity Example

	Customer 1				Customer 2			
	Dist Cap		Monthly Max		Dist Cap		Monthly Max	
Month	Demand	Rate Rev	Demand	Rate Rev	Demand	Rate Rev	Demand	Rate Rev
Jan	2,000	$ 4,166.67	2,000	$ 6,349	2,000	$ 4,166.67	500	$ 1,587
Feb	2,000	$ 4,166.67	2,000	$ 6,349	2,000	$ 4,166.67	500	$ 1,587
Mar	2,000	$ 4,166.67	2,000	$ 6,349	2,000	$ 4,166.67	500	$ 1,587
Apr	2,000	$ 4,166.67	2,000	$ 6,349	2,000	$ 4,166.67	500	$ 1,587
May	2,000	$ 4,166.67	2,000	$ 6,349	2,000	$ 4,166.67	500	$ 1,587
Jun	2,000	$ 4,166.67	2,000	$ 6,349	2,000	$ 4,166.67	500	$ 1,587
Jul	2,000	$ 4,166.67	2,000	$ 6,349	2,000	$ 4,166.67	2,000	$ 6,349
Aug	2,000	$ 4,166.67	2,000	$ 6,349	2,000	$ 4,166.67	500	$ 1,587
Sep	2,000	$ 4,166.67	2,000	$ 6,349	2,000	$ 4,166.67	500	$ 1,587
Oct	2,000	$ 4,166.67	2,000	$ 6,349	2,000	$ 4,166.67	500	$ 1,587
Nov	2,000	$ 4,166.67	2,000	$ 6,349	2,000	$ 4,166.67	500	$ 1,587
Dec	2,000	$ 4,166.67	2,000	$ 6,349	2,000	$ 4,166.67	500	$ 1,587
Annual	24,000	$ 50,000.00	24,000	$ 76,190	24,000	$ 50,000.00	7,500	$ 23,810

Distribution Capacity Charge Pricing

Primary Revenue Requirement
$ 100,000
Total Dist. Cap Demands
48,000
Unit Rate
$ 2.083

Monthly Maximum Demand Pricing

Revenue Requirement
$ 100,000
Total Monthly Max Demands
31,500
Unit Rate
$ 3.175