Q. Provide any reports or evidence filed with regulatory boards by Mr. Greneman of Stone and Webster over the past 10 years in the regulatory jurisdictions identified in his witness profile. (Cost of Service Evidence: Witness Profile)

A. Evidence of Mr. Greneman filed with regulatory boards over the past ten years are identified in the table below and attached in response to this question.

Jurisdiction	On behalf of	Case No.; Year	Subject	Status
Iowa	Midland Electric Co-op	Docket No. FCU-99-3 (C-99-76); 1999	Standby rates	Attached
Indiana	Northern Indiana Public Service Co.	Cause No. 41746; 2001	Electric cost of service	Attached
Indiana	Northern Indiana Public Service Co.	Cause No. 42150; 2002	Environmental tracker	As-filed copy was not retained.
Indiana	Northern Indiana Public Service Co.	Cause No. 42151 & 42658; 2004	Purchased power & transmission tracker	Attached
Louisiana	Southwest Louisiana Electric Membership Corporation	Docket No. U-17355; 2000	Cost of service, realignment of rates, purchased power adjustment clause	Attached
Newfoundland	Newfoundland & Labrador Hydro	2003 GRA	Cost of service, wholesale rate design.	On PUB website
Nova Scotia	Halifax Regional Municipality	NSUARB-P-882; 2005	Street lighting rates	Attached

TRANSMITTAL

FILED WITH
Executive Secretary

AUG 30 1999

IOWA UTILITIES BOARD

DATE:	August 30, 1999
COMPANY NAME:	Midland Power Cooperative
SUBJECT MATTER:	Prepared Testimony of Robert Greneman on Behalf of the Respondent
PERSON TO CONTACT:	Thomas W. Polking and/or John A. Gerken WILCOX, POLKING, GERKEN, SCHWARZKOPF, HOYT & COPELAND, P.C. 115 East Lincolnway, Suite 200 Jefferson, Iowa 50129-2149 Telephone (515) 386-3158 Facsimile (515) 386-8531
INITIAL FILING:	No
DOCKET NUMBER:	FCU-99-3 (C-99-76)

STATE OF IOWA
DEPARTMENT OF COMMERCE
UTILITIES BOARD

IN RE:	)	
	)	
MR. AND MRS. GREGORY SWECKER,	)	DOCKET NO. FCU-99-3
	)	(C-99-76)
Complainants,	)	
	)	
v.	)	
	)	
	)	
MIDLAND POWER COOPERATIVE,	)	PREPARED TESTIMONY OF
	)	ROBERT D. GRENEMAN
Respondent.	)	ON BEHALF OF RESPONDENT

COMES NOW, Robert D. Greneman, on behalf of Midland Power Cooperative, and for his prepared testimony submits the following:

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

A. My name is Robert D. Greneman. I am employed as an executive consultant with the firm of Stone & Webster Management Consultants, Inc., 250 West 34th Street, New York, N.Y. 10119.

Q. Please describe your educational and professional background.

A. I graduated in 1970 from the City College of New York with a Bachelor of Engineering degree in Electrical Engineering. I have also done graduate work at CCNY. From 1973 through 1978 I was employed by Alan J. Schultz, Consulting Engineer (later Casazza, Schultz & Associates), a firm that specialized in economic studies and rate work for electric, gas and water utilities. As an associate engineer my responsibilities included performing cost of service studies, rate design, load forecasting, depreciation studies, economic feasibility studies, valuation studies, plant inspections and the review of power contracts. In 1978 I joined Stone & Webster, where, as a consultant I have continued to assist utility companies in rate and regulatory matters. From 1983 to 1986 I was employed by the Brooklyn Union Gas Company in the Rate & Regulatory Department where I was responsible for conducting the company's cost of service studies, rate design and the review of gas purchase contracts. In 1986 I rejoined Stone & Webster as an executive consultant in the Rate and Regulatory Services Department.

I have prepared numerous cost of service and rate design studies including cost of service studies for: Alpena Power Company, Barbados Light & Power Company, Ltd., Blackstone Valley Electric Company, Brockton Edison Company, Brooklyn Union Gas Company, Central Illinois Light Company, Citizens Utilities Company, City of Westfield, MA, Colorado Electric Company, Commonwealth Edison Company, Dayton Power and Light Company, Delmarva Power & Light Company, Delta Natural Gas Company, Edison Sault Electric Company, El Paso Electric Company, Fall River Electric Light Company, Florida Public Utilities Company, Gas del Estado (Buenos Aires) Gaz Metropolitain, Inc. (Montreal), Green Mountain Power Company, Guyana Electricity Corporation, IGG Utilities (Toronto), Jamaica Water Supply Company, Lake Superior District Power Company, Louiseville Gas & Electric Company, Montana-Dakota

Utilities Co., Newport Electric Corporation, Tampa Electric Company, South Jersey Gas Company, Southern Indiana Gas and Electric Company, Suffolk County Water Authority and Washington Natural Gas Company.

I have provided expert testimony before the Delaware Public Service Commission on cost of service; the Commonwealth of Kentucky Public Service Commission on cost of service; the Michigan Public Service Commission on cost of service and rate design; cost of service and rates before the Indiana Utility Regulatory Commission; and on cost of service before the Federal Energy Regulatory Commission.

I am a licensed professional engineer in the states of New York and New Jersey.

Q. Do you have your Curriculum Vita available that would list your qualifications and experience?

A. Yes, attached at the end of my testimony is a copy of my Curriculum Vita.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present an assessment of the Midland Electric cost of service study as it relates to the development of its Tariff Rate 26.16, applicable to co-generation and small power services, and to comment on appropriateness of the methodologies that were used to develop that rate.

Q. Would you please start out by describing what a cost of service study is?

A. Yes. A cost of service study is a study that focuses on a one-year period of a utility's operations (test-year) in which all of a utility's costs are allocated to customer classes based on factors related to cost causation. At the end of the allocation process a revenue requirement is developed for each class. The class revenue requirement is comprised of three basic cost groups: (1) demand; (2) energy; and (3) customer. Each cost group, when divided by appropriate class billing determinants (kWh sales, kW demand and number of customers) produces unit costs which serve as an important guide in the rate design process.

There are three basic steps in the costing process. They are: (1) functionalization; (2) classification; and (3) allocation.

Q. Please describe each of these steps.

A. A utility's total annual cost, or revenue requirement, is comprised of operating expenses, depreciation expense, taxes, interest expense and margin.

Q. The first step, <u>Functionalization</u>, identifies and assigns each component of the revenue requirement as being related to specific steps in the process of generating, transmitting, distributing, meter reading and billing for electricity.

The second step, <u>Classification</u>, assigns each functionalized cost according to its basis for cost causation, i.e., energy-related, demand-related, or customer-related.

Energy-related costs are those costs that vary directly with the amount of kilowatt-hours (kWh), or energy produced or sold. Fuel and the energy component of purchased power are examples of energy-related costs.

Demand-, or capacity-related costs are those costs that vary with the rate at which energy is produced or sold. Generating plant, transmission substations and lines, distribution substations and some or all of distribution lines are said to be demand-related because the cost of these facilities are related to their capacity to deliver power under peak load conditions.

Customer-related costs are not related to either energy or demand, but rather, are incurred by virtue of the fact that there are customers connected to the system and there are ownership and operating costs associated with meters, services and meter reading and billing.

The third step, <u>Allocation</u>, is the process of allocating, or assigning each functionalized and classified cost group to customer classes by means of allocation factors.

Energy allocation factors are based on kWh sales for each customer class, usually adjusted for losses to the input of the system.

Demand allocation factors for power supply capacity costs may be based on the relative demand of each class at the time of the system peak. For distribution substations and lines that are designed to serve more local, less diversified loads, the demand allocation factor may be based on the maximum demand of the class in a month without regard to the time of occurrence. Customer allocation factors are based on the relative number of customers in each class. Customer allocation factors may also be based on weighted customers, to recognize, e.g. that industrial meters cost more to own and operate than residential meters.

Q. What results does a cost of service study show?

A. At the end of the three-step process, the revenue requirement for each class is separated into categories as illustrated in Table 1, below.

TABLE 1
ELEMENTS OF CLASS REVENUE REQUIREMENT

Function	Components	Category	Unit Costs
Power Supply			
Demand-related	Purchased power demand charges + transmission charges	External Capacity	$/billing kW
Energy-related	Purchased power energy charges	External Energy	$/kWh sales
Distribution			
Demand-related	Substations, distribution lines, line transformers	Internal Capacity	$/billing kW
Customer-related	Meters, services, meter reading, billing & collecting, plus portion of distribution lines and line transformers in some studies.	Internal Customer	$/customer/mo.

Rates that recover revenues that are in relative alignment with class revenue requirements, determined using a cost of service study, are the most widely recognized measure of rates that are equitable and non-discriminatory.

Q. Please explain the last column in Table 1.

A. The last column of Table 1 shows the result of dividing the revenue requirement for each function by billing determinants for the class. These unit costs are not rates per se, but serve as an important guide in developing an appropriate rate structure.

The actual rate design process (for both rate level and structure) may involve many other considerations such as availability of demand metering, maintaining historical rate relationships, value of service and competitive factors, social considerations, the ability of rates to recover allocated costs, and the like.

Q. Turning now to Midland's Cost of Service Study, Exhibit No. 1, would you describe that study?

A. Yes. Exhibit No. 1 is a cost of service study in electronic spreadsheet format that was prepared for Midland by the Iowa Association of Electric Cooperatives (IAEC) for the test-year ended September 30, 1994.

Q. Were the test-year costs used in that study based on Federal Energy Regulatory Commission (FERC) Uniform System of Accounts, or something else?

A. Midland does not use the FERC chart of accounts, but rather, it uses the U.S. Department of Agriculture (USDA) Uniform System of Accounts-Electric as prescribed in RUS Bulletin 1767B-1 (September 1997). Both systems of accounts are very similar, as most of the account numbers and names are the same.

Q. You mentioned that functionalization was the first step in the costing process. Where is this shown in Midland's cost of service?

A. The functionalization and classification steps are typically performed together. These steps are shown on Workpaper No. 1 of Exhibit No. 1.

Q. What functions were used in the study?

A. All costs were functionalized into four functions. They are:

(1) Internal Customer
This function captures costs that are classified as customer-related, including meters, services, meter reading, billing and collecting, plus a portion of distribution lines and line transformers.

(2) Internal Capacity
This function captures costs associated with receiving power and energy from its suppliers and distributing it to customers. These costs are classified as demand-related, and include substations and a portion of distribution lines, and line transformers.

(3) External Capacity
This function captures costs associated with purchases from Midland's power suppliers for generation and transmission capacity that are as-billed on a demand basis.

(4) External Energy
This function captures power supply costs from Midland's suppliers that are billed on an energy basis.

Table 1, above, also summarizes the components of these four functions.

Q. Please go on to describe the functionalization methodology that was used.

A. The cost of service study structure and methodologies used in the study were jointly developed by the IAEC and the Iowa

Utilities Board (IUB) when Midland Power Cooperative became rate regulated in 1976.

Lines 1 through 8 of Workpaper No. 1 set forth the functionalization of operating expenses. Purchased power was functionalized between external capacity and energy classifications based on the manner in which these costs were incurred.

Distribution operation and maintenance (O&M) expenses were not functionalized by primary account, but rather, were classified in aggregate, 50 percent to the internal capacity function and 50 percent to the internal customer function. Customer accounts expense and sales expenses were assigned 100 percent to the internal customer function. Administrative and general (A&G) expenses were functionalized between the internal capacity and customer functions based on the sub-total of O&M expenses, excluding A&G.

Lines 9 through 16 of this workpaper show the functionalization of other fixed operating expenses. Depreciation expense for distribution plant was classified 50 percent to the internal capacity function and 50 percent to the internal customer function. Depreciation expense for general plant was assigned directly to the internal capacity function.

Property taxes for distribution lines were split 50/50 between the internal capacity and customer functions. Other property taxes and taxes other than property taxes were functionalized between the internal capacity and customer functions based on the sub-total of O&M expenses, excluding A&G.

Short-term interest was assigned to the internal customer function. Long-term interest was functionalized between the internal capacity and customer functions based on an analysis of depreciation reserve contained in Workpaper No. 4.

Q. Please describe the allocation process in Midland's cost of service study.

A. The allocation step is contained in Workpaper No. 2, sheets 2a, 2b and 2c.

In this schedule, the functionalized and classified totals for each of the four functions were carried forward from Workpaper No. 1.

Internal capacity costs were allocated to customer classes based on their non-coincident demands. Demands for the non-demand-metered classes were estimated using the REA AB Methodology as described in its Bulletin No. 45-1.

Internal customer costs were allocated based on the number of customers in each rate class. For separately metered electric heat and lighting classes, a weighting factor of 10 percent was applied to recognize they are a secondary service on another primary rate schedule.

External capacity represents the demand charges of both of Midland's suppliers -- CIPCO and Corn Belt. The total demand charges from these suppliers were allocated using an estimate of the coincident peak for each class in order to reflect the manner in which it is billed for power. For dual-fuel and interruptible rates, external demand costs were computed separately. For the demand-metered classes the Bary Curve was used to estimate the contribution to the system coincident peak based on the measured billing demands and the load factor of the class.

Q. What do the results of the allocation step show for Midland's three-phase service rate?

A. The results in Exhibit No. 1, Workpaper Nos. 2 and 3, show allocated costs for this class of $622,126 and proposed revenues of $669,019. Table 2, below, summarizes the costs by function along with unit costs that were computed by dividing allocated costs in each function by billing determinants for the class.

TABLE 2
SUMMARY OF COST STUDY RESULTS FOR 3-PHASE CLASS

Cost Component	Allocated Costs	Bills/kWh/kW	Unit Cost
Internal Customer	$ 62,415	2,556 bills	$24.42/month
Internal Capacity	143,775	2,556 bills	$56.25/month
External Demand	279,453	18,696 kW-yr.	$14.95/kW/mo.
External Energy	136,483	7,948,247 kWh	$0.01717/kWh

Total	$ 622,126		

Q. How did Midland use these results to develop its Rate 26.11?

A. Rate 26.11 reflects a consolidation of rates for existing customers that were being billed under Greene, Hardin and Hardin Demand rates. To provide an overview of the rationale used in designing this three-phase rate, the monthly service charge was set at three times the $12.00 per month service charge applicable to the single-phase class, or $36.00 per month. A three-step declining-block structure was developed, in which the first two blocks were designed to recover the balance of Midland's ready-to-serve internal costs with the tail block set at $0.056/kWh - this level approximating the base for its Energy Adjustment Clause (EAC). Consumption levels for blocks one and two and their associated rates were set based on other considerations, but such that the rate produced target revenues of $669,019.

Q. Did you prepare a computation showing how Rate 26.11 produces the correct revenues?

A. Yes. Exhibit No. 3 is a rate/revenue computation which shows that Rate 26.11 produces revenues of $668,973, or $46 shy of the target.

Q. Turning now to Midland's Three-phase Co-generation Rate 26.16, please discuss the rationale used in the development of this rate.

A. I would like to begin by noting that because of the different operating characteristics of sales customers and co-generation customers, it would be inappropriate to simply use Rate 26.11 for co-generation sales.. There are two main concerns.

The first deals with Midland's internal capacity and customer costs. Internal capacity costs include system substations, distribution lines and line transformers that are used to deliver power and energy from the receiving stations to where customers are located. Internal customer costs include costs associated meters, services, meter reading and billing. All of these costs are fixed in nature, i.e., they do not vary with the amount of kilowatt-hours consumed. Regardless of its level of sales, Midland must meet its financial ownership and operating costs for these facilities. These obligations are comprised of: operation and maintenance expense, depreciation expense, property taxes, other taxes, interest expense and margin.

In cost of service theory and as most widely practiced:

1. Distribution facilities (substations and lines) are designed to meet a peak demand level, and customer classes that contribute to that peak (usually non-coincident with the system peak) are allocated a proportionate share of all such costs. In practice, factors such as the class diversified demand, or customer individual demands are used to allocate these costs between classes.

2. Customer costs (meters, services, meter reading and billing) are simply incurred by virtue of the fact that a customer is connected to the system.

Thus, the *trigger* for incurring internal demand costs is contributing to a single class peak and for incurring internal customer costs is being a customer. Once cost responsibility is attributed to a class, it continues for the entire test-year.

On a regular sales rate such as for single- or three-phase service, the recovery of these costs are typically, partly recovered through a service charge and partly through an energy charge. Based on the historical usage patterns of such classes, there is a more than reasonable expectation that all fixed annual costs will be recovered.

For a co-generation facility, however, in which a reliable sales level or pattern is not known, to put fixed costs in the usage charge would put Midland at significant risk for underrecovery of its internal costs.

To remedy this situation, Three-phase Co-generation Rate 26.16 features an $86.00 per month service charge, which essentially recovers 96 percent of the $89.56 cost of service based customer charge (Exhibit 4, page 3).

Q. Please discuss your other concern as to why it would be inappropriate to apply three-phase sales Rate 26.11 to co-generation sales.

A. My other concern also relates to the unknown sales level and load profile of a co-generator, but as it relates to Midland's external capacity costs. Midland's regular three-phase service Rate 26.11 does not have a demand charge, but was designed to recover coincident peak-related power supply costs through its energy charges. If a co-generator required service during the peak period, it would cause Midland to incur demand costs from its suppliers, but the co-generator would likely not use sufficient energy through the balance of the month to allow recovery of the costs incurred. Thus, in the three-phase co-generation Rate 26.16, coincident peak-related power supply demand charges were moved from the energy charge and stated as a demand charge in order to explicitly recognize on-peak usage.

In addition, Midland's suppliers also charge a non-coincidental hourly demand charge of $4.00/kW. This charge, which is built into Rate 26.11, was also included in Rate 26.16 to capture non-coincidental off-peak demand costs incurred by a co-generator.

Q. Did you prepare a schedule that shows the equivalency of Rate 26.11 and Rate 26.16?

A. Yes. Exhibit 4 sets out costs and rates under: (1) a strictly cost of service-based rate structure; (2) Rate 26.11 applicable to three-phase service; and (3) Rate 26.16 applicable to three-phase service to a co-generation facility. This exhibit starts with cost of service and shows the equivalence of cost based rates for each of the three cases on a per customer basis.

Q. Please take us through this exhibit in greater detail.

A. Section I shows the allocated costs per the cost of service study and the target revenue level to be used for rate design. Line 4 of this schedule prorates the revenue target to each of the four functions based on allocated costs in each. The results show that of the $669,019 to be recovered, $221,732 is related to internal demand and customer and $447,287 is related to external demand and energy.

In developing a strict cost-based rate structure, internal and external costs were divided by class billing determinants and adjusted by a revenue adjustment factor of 0.96861 (developed in Schedule 3).

Under this cost-based rate structure, an average three-phase service customer would have a monthly bill of $261.75

Section II supports the cost-based rate design for three-phase Rate 26.11. The cost-based customer charge of $89.56 was lowered to $36.00 and the cost-based demand charge of $16.59 was lowered to zero. The unrecovered portion of the service and demand charges were then added to the energy charge. Line 32 shows the same $261.75 monthly bill is paid by the average customer after the rate restructuring.

Section III supports the cost-based rate design for three-phase co-generation Rate 26.16. Using a similar procedure set out in Section II, the cost based customer charge was lowered from $89.56 to $86.00 and the cost-based demand charge of $16.59 was lowered to $15.90. This resulted in an energy charge of $0.02184/kWh (Section II, Col.(6), line 95). For a average customer having an average three-phase load profile, this results in a monthly bill of $261.75 (Col.(9), line 99.

Q. Why is the energy charge of $0.030/kWh in Rate 26.16 greater than the energy charge of $0.02184/kWh you show in Section III?

A. As mentioned earlier, Midland is billed for a $4.00/kW hourly demand charge from its suppliers which is not reflected in the $0.02184 energy charge developed in Section III. Although it is included in the $15.90/kW coincident demand charge, it is incurred when *any* demand is imposed by the co-generator, but cannot be collected unless the co-generator imposes a coincidental demand. On the other hand, when the co-generator imposes a non-coincidental demand it will not likely use sufficient kWh over the month to fully recover the $4.00 cost. Section III - D shows the treatment accorded the $4.00/kW hourly demand charge. In this calculation, the $4.00/kW demand charge was expressed as an energy charge of $0.00971 based on an average three-phase class load factor. Since a co-generator would most likely have a much lower load factor the charge may be significantly understated. However, the inclusion of this charge brings the Rate 26.16 energy rate up to $0.03156/kWh, which was further rounded down to the published rate of $0.030/kWh.

Q. What is your assessment of the manner in which Three-phase Co-generation Rate 26.16 was designed.

A. My assessment is that the three-phase co-generation rate 26.16 is cost-based. My testimony and exhibits prove in a step-wise fashion the fact that Rate 26.16 is based on cost of service, in terms of both rate level and rate structure and was developed using the same principles that were used in the development of Rate 26.11.

In Exhibit 4, I started with a cost-based rate structure and have shown how Rate 26.11 was developed by recovering costs allocated to the class using a different combination of service and energy charges. This schedule then shows how another combination of service, energy and demand charges recovers the same class costs for co-generation Rate 26.16. In fact, many sets of combinations are possible.

Q. What common principles were utilized in the design of Rates 26.11 and 26.16?

Let me begin by pointing out that the Midland cost of service study used the same costing methodology and rate design principles for its three-phase service class as it did for its other classes. However, I should also note that in terms of rate design, customers that take service under Rates 26.11 and 26.16 are not similarly situated customers. This is due to the fact that Rate 26.11 customers have a reasonably predictable historical load profile. Co-generation customers, on the other hand, are expected to have an unknown or sporadic load profile, which may literally change depending on which way the wind is blowing.

One widely recognized rate design principle is that <u>the utility must have a reasonable expectation of recovering the costs that the customer causes it to incur, from the customers that cause the cost incurrence</u>. This was the common principle employed in the design of both rates. In particular, if Rate 26.11 was to be applied to co-generation sales, Midland should expect a significant revenue shortfall. In order to remain whole, it would have to raise its rates to other sales classes, resulting in a subsidization to co-generation customers by other customers. I would characterize this as discriminatory against Midland's other customers.

Another common principle is that in the costing and rate design process, classes are grouped together based on having similar load characteristics and usage patterns. Under this consideration, 26.16 and 26.11 clearly have different load profiles and should be treated separately.

Indeed, industry-wide, utilities have developed separate standby and co-generation sales rates in recognition of the need to recover their costs when sporadic sales are anticipated.

Customers must support costs they incur and not be subsidized by other classes.

My conclusion is that the rates and service classifications established by Midland, including its co-generation rates in 26.16 do apply rates equitably to similarly situated customers and in a non-discriminatory manner.

Q. Are there any other cost or rate issues you wish to address in connection with these rates?

A. Yes. One other cost issue that deals with any additional metering needed to implement sales to and from a co-generation facility. I believe that the co-generation facility should be responsible for the cost of such metering equipment. If the utility were to assume responsibility for this cost it would have the effect of other sales customers subsidizing the co-generator.

Q. Does this conclude your testimony?

A. Yes, it does.

Northern Indiana Public Service Company
Cause No. 41746
Respondent's Exhibit RDG-1

DIRECT TESTIMONY OF ROBERT D. GRENEMAN

1. Q. Please state your name, occupation and business address.

A. My name is Robert D. Greneman. I am an Associate Director in the Markets, Finance and Regulation group with the firm of Stone & Webster Consultants, Inc., 1 Penn Plaza, New York, N.Y. 10119.

2. Q. Please describe your educational and professional background.

A. I graduated in 1970 from the City College of New York with a Bachelor of Engineering degree in Electrical Engineering. I have also done graduate work at CCNY. From 1973 through 1978 I was employed by Alan J. Schultz, Consulting Engineer (later Casazza, Schultz & Associates), a firm that specialized in economic studies and rate work for electric, gas and water utilities. As an associate engineer my responsibilities included performing cost of service studies, rate design, load forecasting, depreciation studies, economic feasibility studies, valuation studies, plant inspections and the review of power contracts. In 1978 I joined Stone & Webster, where, as a consultant I have continued to assist utility companies in rate and regulatory matters. From 1983 to 1986 I was employed by the Brooklyn Union Gas Company in the Rate & Regulatory Department where I was responsible for conducting the Company's cost of service studies, rate design and the review of gas purchase contracts. In 1986 I rejoined Stone & Webster as an executive consultant in the Rate and Regulatory Services Department.

I have prepared numerous cost of service and rate design studies for clients including: Alpena Power Company (MI), Barbados Light & Power Company, Ltd., Blackstone Valley Electric Company, Brockton Edison Company, Central Illinois Light Company, Chesapeake Utilities Corporation, China Light & Power Company, Ltd. (Hong Kong), Citizens Utilities Company, City of Westfield, MA, Colorado Electric Company, Commonwealth Edison Company, Consolidated Edison Company of New York, Dayton Power & Light Company, Delmarva Power & Light Company, Delta Natural Gas Company, Edison Sault Electric Company, El Paso Electric Company, Equitable Gas Company, Fall River Electric Light Company, Florida Public Utilities Company, Gas del Estado (Buenos Aires), Gaz Metropolitain, Inc. (Montreal), Green Mountain Power Company, Guyana Electricity Corporation, Holyoke Department of Gas & Electric (MA), ICG Utilities (Toronto), Jamaica Water Supply Company, Lake Superior District Power Company, Louisville Gas & Electric Company, Montana-Dakota Utilities Co., Midland Electric Power Cooperative (IA), Newport Electric Corporation, Roseville Electric (CA), Tampa Electric Company, South Jersey Gas Company, Southwest Louisiana Electric Membership Corporation, Southern Indiana Gas and Electric Company, Suffolk County Water Authority (NY), Valley Gas Company and Washington Natural Gas Company

I have provided expert testimony before the Delaware Public Service Commission, the Commonwealth of Kentucky Public Service Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board and the Federal Energy Regulatory Commission.

I am a licensed professional engineer in the states of New York and New Jersey.

3. Q. What was your assignment in this proceeding?

A. I was asked by the Company to prepare a fully-allocated cost of service study which serves the following functions:

(1) Separates costs between the Company's Indiana jurisdictional business and its non-jurisdictional, or wholesale business - these costs falling under the regulation of the Federal Energy Regulatory Commission; and

(2) Develops the cost of service for each of the Indiana jurisdictional retail classes of service.

4. Q. Have you prepared exhibits which accompany your testimony in these areas?

A. Yes, a schedule of the cost of service study results, which summarizes operating income, rate base and rates of return earned for the wholesale and retail segments of the business, as well as for each retail class of service, is attached to my direct testimony as Respondent's Exhibit RDG-2. These results will be discussed in more detail later on in my testimony. The actual cost of service study that I have prepared is being submitted in the working papers.

5. Q. What test-period was used in your study?

A. The cost of service study was based on the audited financial results of the Company's electric operations for the twelve months ended December 31, 1999 and included pro forma adjustments by NIPSCO witnesses Vajda and McKnight shown in Respondent's Exhibit DJV-5 and BAM-2, respectively. The study used fair value rate base developed by NIPSCO witness Reed and Kelly, shown in Respondent's Exhibits JAR-1, JPK-1, respectively.

6. Q. Please describe the general allocation procedures that you used in preparing your cost of service study?

A. The cost of service study uses a three-step approach of functionalization, classification and allocation.

1. Functionalization assigns all plant and expenses to the basic steps involved in the process of producing, transmitting, distributing and billing for electricity;

2. Classification further assigns costs for each function as being demand-, energy- or customer related; and

3. Allocation is the process of apportioning each functionalized and classified cost group to classes of service based on factors related to cost causation.

The functionalization and classification steps were done together and are contained in the Functionalization section of the cost study. The allocation step is contained in a separate section by that name. The first page of the Allocation section summarizes rates of return by rate schedule or class of service.

<u>Functionalization</u>

7. Q. Please describe the first step, functionalization in greater detail.

A. The first step, functionalization, is the definition of the major cost groupings that represent the basic steps in the production, transmission, distribution and billing of electricity. The process involves assigning plant, reserve, operation and maintenance, depreciation and tax expense to the appropriate functions involved.

The cost of service study is comprised of 31 functions. The functions used were generally defined for any the following basic reasons:

1. To track costs by predefined functions and sub-functions;

2. To separate costs within functional categories that are not allocated in the same way to customer classes. For example Production was separated into demand and energy components to capture costs associated with generating plant versus fuel expense. (This process is also known as Classification.); and

3. To track costs such as meter reading and billing that are more properly associated with customer classes.

The functionalization process begins with the Company's Uniform System of Accounts, in which plant, depreciation reserve, operation & maintenance expenses and depreciation expense have generally been classified into production, transmission and distribution functions.

Within the distribution function, the individual primary accounts from the Uniform System of Accounts were then assigned to their associated distribution functions and sub-functions in the cost of service study. These included categories such as, substations, lines, line transformers, services, meters and lighting. Book depreciation reserve, which was known by primary account, along with depreciation expense, were assigned to functions in a similar fashion to plant.

General plant, which cannot be directly associated with particular functions, was functionalized on the basis of labor ratios. These ratios were developed by functionalizing the labor in each primary O&M account (excluding A&G) in the same manner as the functional distribution of the corresponding O&M account. The use of labor for the allocation of general plant is a widely accepted industry practice. It might be noted that this methodology allows plant costs associated with customer functions such as meter reading and billing to be captured, as there are not separate plant accounts for these activities.

Administrative and general expenses were generally also functionalized on the basis of labor, except that property insurance was functionalized on plant, and outside services, general advertising, miscellaneous general expense and rents were functionalized on a weighting factor comprised of 50% plant and 50% labor.

Taxes other than income taxes were broken down by type of tax. Each type was functionalized according to its basis for cost causation. For example, property taxes were functionalized on plant, employment-related taxes were functionalized on labor and gross income taxes were assigned to the function Revenue Taxes for allocation to classes in a later phase of the study.

8. Q. What was the rationale for having five production functions?

A. Fixed or capital-related costs were divided into three categories:

1. Production Fixed (Steam and Hydro);

2. Production Fixed (Combustion Turbines); and

3. Production Variable.

The Production Fixed (Combustion Turbine) function was created to track costs associated with combustion turbines, a portion of which is to be assigned to a particular wholesale customer in the allocation phase of the study.

The Production Variable function was created to track costs that are fixed in nature but are indirectly related to kWh produced or sold. These include costs such as fuel stock and a portion of labor and materials for boiler maintenance of the Company's steam units.

The Production Fixed (Steam and Hydro) function represents the fixed capital and operating costs of hydro and the portion of steam facilities that were not assigned to the Production Variable function.

The remaining two functions, Purchased Power Demand and Fuel and Purchased Power Energy functions are self-explanatory.

9. Q. How were distribution lines functionalized between primary and secondary?

A. An estimate of poles carrying primary versus secondary voltage was made based on a database query to show the quantity of poles by height for poles carrying primary only, secondary only, and primary or secondary with various combinations of street lighting fixtures, line transformers and services. As a result of this query it was estimated that 57% of the cost of poles in Account 364 was serving primary and 43% was serving secondary.

Distribution overhead conductors were functionalized between primary and secondary voltages by reviewing a summary of the Company's wire types and costs and applying judgement as to whether particular conductor types served a primary or secondary voltage. Based on this review it was estimated that approximately 89% of conductors carried primary and 11% carried secondary.

<u>Classification</u>

10. Q. Please describe the process of classification.

A. The second step in the costing process is classification. In this step, each functionalized cost group is separated into demand-, energy- and customer-related components based on the predominant factor for cost causation.

Some costs are related to the quantity of energy produced or sold. These are known as energy-related costs. The cost of fuel and the energy component of purchased power are examples of energy-related costs.

Demand- or capacity-related costs are those associated with maximum rates of use of energy, or demand. Most capital costs are demand-related because the investment in facilities is related to the size of the facility and facilities are sized to provide service under peak demand conditions. Generating facilities, transmission and a portion of distribution lines and line transformers are examples of demand-related costs. However, the peak demand condition each component is designed to meet may be different for each type of facility.

Customer-related costs are those that are associated with serving customers regardless of either the amount of energy used or the maximum demand. For example, every customer has a meter and a service and the costs associated with metering and billing are not related to consumption. These costs are commonly considered to be allocable on factors that are related to the number of customers.

Functionalization and classification are commonly done in the same step. For example, in functionalizing O&M expenses, operating expenses associated with generating facilities may be functionalized and classified to Production Demand, whereas the fuel account will be functionalized and classified to Production Energy. General plant and administrative & general expenses were also functionalized and classified at the same time.

Revenue-related costs such as uncollectible accounts and gross income taxes were assigned to their own respective functions. These costs may be functionalized at a later stage based on the sub-total of the functionalized and classified cost of service for each customer class.

11. Q. How did you classify distribution system costs in the cost of service study?

A. Primary lines, line transformers and secondary lines were classified between customer- and demand-related components based on the use of a minimum system. The rationale in support of this concept is that there is a theoretical system of minimum-diameter conductors supported by minimum height poles that connects each customer to the backbone transmission system and power supply, standing by and ready provide a minimal level of service. This skeleton system which is a function of the expanse of the service territory and concentration of customers is allocable based on the number of customers in each class, rather than the maximum demand imposed during the peak hour, while the balance of costs are incurred to meet peak demand. Conceptualized another way, whereas pole height and conductor diameter are related to meeting peak demand levels, the number of poles and conductor length are related to physically connecting customers.

A minimum system estimate by the Company found that primary and secondary pole investments were split 60% customer and 40% demand, and that its distribution wire investment was split 50% customer and 50% demand. In my cost of service study, I have moderated these findings to 50% customer and 50% demand for both poles and wire.

The customer component of line transformers was developed based on the ratio of a minimum capacity value of 1.5 kVA per customer divided by an average installed capacity of 11.75 kVA per customer, or 12.77%.

<u>Allocation</u>

12. Q. Please go on to describe the third step in the costing process.

A. The third step, allocation of costs, is the process of cost assignment whereby each class of service receives a proportionate cost responsibility for each of the functionalized and classified cost groups. This is accomplished by means of allocation factors, which are based on the ratio of the amount of demand, energy sold, or number of customers for each class of service to the company total.

13. Q. What classes of services were included in your study?

A. The retail classes of service were generally defined by each of the individual rates in the Company's tariff under which customers took service in the test-year. The wholesale portion of the business was separated into six classes. They are:

1. Full requirements sales to Cities and Towns – 1 customer;
2. Firm wheeling to Cities and Towns – seven customers;
3. Firm wheeling to Wabash Valley Power Authority (WVPA);
4. Firm wheeling to the Indiana Municipal Power Agency (IMPA);
5. Non-firm sales – comprised of economy sales, and 90 MW of peaking unit reservation to WVPA
6. Non-firm wheeling – non-firm wheeling, plus operating and spinning reserve requirements and miscellaneous revenues.

To allocate demand-related costs, factors were developed for each type of facility based on a measure of the maximum load imposed on the facility, recognizing: (1) customer load served at each voltage level; (2) an increasing level of diversity associated with upstream facilities; and (3) losses.

The demands used in the cost study were based on control area peaks and company load research data for calendar year 2000. 2000 was used due to abnormal weather conditions in 1999 in which the Company experienced a summer with approximately 38% more cooling degree-days than normal. 2000 was judged to be more representative of normal weather than 1999.

14. Q. What was the treatment accorded generation and transmission?

A. Plant and expenses functionalized to the generation and transmission functions were allocated on the basis of the contribution of each class of service to the four-month (June through September) average control area peak.

15. Q. Why did you use this approach?

A. I have utilized four tests suggested by the Federal Energy Regulatory Commission (FERC) as a basis for selecting an appropriate demand allocator. These tests are as follows:

1. To compare the average of the system peaks during the purported peak months as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak;
2. To examine the ratio of the lowest monthly peak to the annual system peak;
3. To review the extent to which peak demands in non-peak months exceed peak demands during the peak months; and
4. To review the average of the twelve monthly system peaks as a percentage of the system peak.

16. Q. What did the results of these tests show?

A. Using data for calendar year 2000, test 1 shows that the average of the system peaks for the eight off-peak months was 82.6 percent of the average of the peaks for the months June through September. Test 2 shows that the lowest monthly peak was 71.8 percent of the highest monthly peak. Test 3 shows that there were no non-peak months in which the peak exceeded the peak demand in any peak month. Finally, the average of the 12 monthly system peaks was 83.9 percent of the annual system peak. The results of these tests support the use of a 4 coincident peak methodology as being a reasonable measure for the allocation of production and transmission costs in the cost of service study.

17. Q. Did you also use a four-month average methodology to allocate costs to the non-jurisdictional classes?

A. Yes, generation and transmission costs were allocated to the firm sales and wheeling customers on a consistent basis, using the same four-month average methodology.

18. Q. How were generation and transmission costs assigned to the non-firm sales class shown in your study?

A. The Non-Firm Sales class is comprised of two components. They are: (1) non-firm sales to other utilities; and (2) 90 MW of peaking unit reservation to Wabash Valley Power Authority (WVPA).

The non-firm sales to other utilities were considered to be opportunity sales, having only out-of-pocket expenses associated with such sales. These out-of-pocket expenses primarily consisted of fuel and purchased power. Based on an analysis by the Company of the resources involved in making these non-firm sales, $64,705,862 of cost was assigned to this class. This corresponds with a revenue figure of approximately $67,660,000.

Fixed capacity costs associated with combustion turbines were directly assigned to WVPA based on the relationship of its call on 90 MW to a total of 203 MW of available gas turbine capacity. The balance of fixed costs associated with combustion turbines was allocated to all remaining sales customers using the four-month average methodology.

18. Q. How did you treat non-firm wheeling?

A. Non-Firm Wheeling is actually comprised of four components. As a percent of revenues for this class they are: (1) wheeling and transmission reservation fees (94.9%); (2) operating reserves capacity (3.9%); (3) spinning reserve requirements (0.43%); and (4) miscellaneous services revenues (0.74%).

Transmission costs were allocated to non-firm wheeling in a similar fashion as firm transmission customers, i.e., based on their average contribution to the control area peak during the months of June through September.

Operating reserves capacity refers to the Company's need to make up the difference between scheduled and actual transmission deliveries, or imbalances, for two wheeling customers, Wabash Valley and IMPA. The procedure used to assign costs to this function was to allocate generation based on an average 2.5% imbalance level of the average hourly demand of these customers.

Spinning reserve requirements refers to the Company's mandate to have a 5.91% spinning reserve requirement on its energy purchases from a small generation facility owned by Waste Management. The procedure used to assign costs to this function was to allocate generation based on the spinning reserve requirement applied to average hourly load during 1999.

Miscellaneous services revenues refers to billing of services by the Company's Environmental Department to other subsidiary companies. In assigning costs, it was assumed that these services were billed to the subsidiaries at actual cost. Therefore, in the cost study, an assignment was made from A&G Salaries (Account 920) to non-jurisdictional equal to the revenues received.

19. Q. How were distribution system costs assigned to classes?

A. The Company's distribution system was sub-functionalized into 11 categories as follows:

1. Distribution Substations - General;
2. Distribution Substations – Railroad;
3. Distribution Substations – Interdepartmental;
4. Distribution Substations – Wholesale;
5. Distribution Lines – Primary-Demand;
6. Distribution Lines – Primary-Customer;
7. Distribution Lines – Wholesale;
8. Distribution Lines – Secondary-Demand;
9. Distribution Lines – Secondary-Customer;
10. Line Transformers – Demand; and
11. Line Transformers – Customer.

Distribution Substations-General, Distribution Lines-Primary and Line Transformers-Demand were allocated based on the maximum annual class demand, i.e., the maximum diversified demand of all customers within a class without regard to the time of occurrence.

Distribution Lines Secondary-Demand was allocated based on the maximum class undiversified demand, i.e., the arithmetic sum of the maximum annual demand of each customer within the class, assuming all customers were demand metered.

In all, three types of demand factors were used in the study:

1. Class demand coincident with the control area peak;
2. Maximum class demand without regard to the control area peak; and
3. Sum of maximum customer demands within a class

Each successive demand type, above, reflects a decreasing level of diversity of load and was applied in the study to successively lower voltage level facilities. This was done because as voltage level decreases, facilities are sized to serve loads that are progressively more local in nature, and therefore less diversified.

The demands used were adjusted for losses from the customer's meter to reflect the load at the specific facility being allocated. The demand factors also reflect the load of customers that actually take serve at that particular voltage level. Voltage level of service data by customer class was developed with the assistance of a Customer Information System (CIS) download performed by the Company, which summarized kWh sold by voltage level of service by customer class for the test-year.

The class demands used were based on load research conducted and compiled by the Company for the calendar year 2000.

The customer components of primary lines, line transformers and secondary lines were allocated to classes based on the number of customers served at each voltage level.

The functions Distribution Substations-Railroad and –Interdepartmental were used to directly assign the substations that serve the railroad customer on Rate 844 and other Company facilities, including its LNG plant.

The functions Distribution Substations-Wholesale and Distribution Lines-Wholesale were used to directly assign costs to the wholesale classes.

20. Q. How were distribution costs to assign to wholesale?

A. Direct assignments of distribution substations and lines were made to the following wholesale classes:

1. Cities and Towns - Full Requirements, comprised of the Town of Argos;
2. Cities and Towns – Wheeling; comprised of seven customers including: Bremen, Brookston, Chalmers, Etna Green, Kingsford, Walkerton and Winamac;
3. Wabash Valley Power Authority (WVPA); and
4. Indiana Municipal Power Agency (IMPA).

The Company serves the cities and towns and Wabash Valley at numerous delivery points along its distribution system. To best determine the distribution facilities that serve these customers detailed reviews were made of all distribution substations and lines that are involved in serving wholesale load.

The first review involved an analysis of all distribution substations that serve firm wholesale sales and wheeling customers. For each substation, the portion assignable to wholesale customers was determined by multiplying the substation cost by the ratio of the annual maximum load of the wholesale customers served from the substation to the maximum annual load on that substation.

The second review involved an analysis of all distribution lines that served wholesale and wheeling customers. For each distribution line that served a wholesale delivery point, costs were assigned to wholesale by multiplying the average cost per mile of distribution lines by: (1) the miles of line needed to reach a particular wholesale delivery point; and (2) the ratio of the wholesale max load at the delivery point to the max load of the line.

Using this procedure, costs directly assignable to wholesale were split between the appropriate FERC accounts and assigned to the particular wholesale classes involved.

Since IMPA is a transmission wheeling customer, the only distribution costs assigned were those related to metering and facilities needed to interconnect with the customer-owned substations.

21. Q. How were interruptible customers treated in the cost study?

A. The coincident demands of interruptible customers on Rates 825, 836 and 847 were weighted 50 percent to recognize the interruptible nature of their service.

22. Q. How were energy-related costs allocated in the cost study?

A. Fuel and the energy component of purchased power expense were allocated based on pro forma kWh sales adjusted for losses to the generation bus bar.

23. Q. How were customer-related costs allocated?

A. Meters, services, meter reading, billing & collecting, customer service & informational expense and sales expenses were generally allocated to customer classes based on weighting factors for each class times the number of customers in the class. The weighting factor for each class was expressed in terms of the cost for that class divided by the cost for residential.

Weighting factors used for meters (Account 370) were based on a Company analysis of the average installed cost of a meter installation by customer class.

Weighing factors for services (Account 369) were developed based on a 50% weighting of number of customers by class and a 50% weighting of the square-root of the average use per customer times the number of customers in the class.

Meter reading, billing & collecting, customer service & informational expenses and sales expenses were developed based on discussions with the Company as to the costs involved. Costs associated with hand-billing larger customers were estimated and directly assigned.

24. Q. How were income taxes assigned to classes?

A. State and Federal income taxes were actually computed for each class by applying the applicable tax rates to the class taxable income amount. The class taxable income was computed based on revenues less operating expenses and interest expense and other adjustments for tax purposes.

25. Q. What are the results of the allocation phase of the study?

A. The results of the allocation phase of the cost of service study are summarized on Respondent's Exhibit RDG-2. They are presented in the form of an income statement that computes the return earned on fair value rate base for each of the classes that comprise the Company's wholesale and Indiana jurisdictional segments of the business. These results show that the Indiana jurisdictional fair value rate base is $4,806,515,482 and net operating income is $210,218,034. These amounts are also reflected on BAM-3 and BAM-5, with minor rounding differences.

For the Company's retail business, rates of return are shown for each service classification under which customers took service during the test-year. These rates of return are a measure of the adequacy of the rates that were in effect during the test-year. The results show rates of return that are relatively flat across all classes.

26. Q. Does this complete your direct testimony in this proceeding?

A. Yes.

EXHIBIT B-4

PREFILE TESTIMONY

OF

ROBERT GRENEMAN, P.E.
STONE AND WEBSTER MANAGEMENT CONSULTANTS
NEW YORK, NEW YORK

SUPPORTING THE REQUIREMENTS FOR ADDITIONAL REVENUE, DESCRIBING THE POWER ADJUSTMENT CLAUSE MECHANISM, DESCRIBING THE 1999 UNBUNDLED COST OF SERVICE STUDY and MODIFICATIONS TO EXISTING RATES

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

DOCKET NO. U-17355

PREFILED TESTIMONY OF ROBERT GRENEMAN, P. E.

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

A. My name is Robert D. Greneman. I am employed as an executive consultant with the firm of Stone & Webster Management Consultants, Inc., 250 West 34th Street, New York, N.Y. 10119.

Q. Please describe your educational and professional background.

A. I graduated in 1970 from the City College of New York with a Bachelor of Engineering degree in Electrical Engineering. I have also done graduate work at CCNY. From 1973 through 1978 I was employed by Alan J. Schultz, Consulting Engineer (later Casazza, Schultz & Associates), a firm that specialized in economic studies and rate work for electric, gas and water utilities. As an associate engineer my responsibilities included performing cost of service studies, rate design, load forecasting, depreciation studies, economic feasibility studies, valuation studies, plant inspections and the review of power contracts. In 1978 I joined Stone & Webster, where, as a consultant I have continued to assist utility companies in rate and regulatory matters. From 1983 to 1986 I was employed by the Brooklyn Union Gas Company in the Rate & Regulatory Department where I was responsible for conducting the Company's cost of service studies, rate design and the review of gas purchase contracts. In 1986 I rejoined Stone & Webster as an executive consultant in the Rate and Regulatory Services Department.

I have prepared numerous cost of service and rate design studies including the development and review of applicable pro forma, annualization and normalization adjustments. I have conducted such studies for clients such as: Alpena Power Company (MI), Barbados Light & Power Company, Ltd., Blackstone Valley Electric Company, Brockton Edison Company, Central Illinois Light Company, Chesapeake Utilities Corporation, China Light & Power Company, Ltd. (Hong Kong), Citizens Utilities Company, City of Westfield, MA, Colorado Electric Company, Commonwealth Edison Company, Consolidated Edison Company of New York, Dayton Power & Light Company, Delmarva Power & Light Company, Delta Natural Gas Company, Edison Sault Electric Company, El Paso Electric Company, Equitable Gas Company, Fall River Electric Light Company, Florida Public Utilities Company, Gas del Estado (Buenos Aires), Gaz Metropolitain, Inc. (Montreal), Green Mountain Power Company, Guyana Electricity Corporation, Holyoke Department of Gas & Electric (MA), ICG Utilities (Toronto), Jamaica Water Supply Company, Lake Superior District Power Company, Louisville Gas & Electric Company, Montana-Dakota Utilities Co., Midland Electric Power Cooperative (IA), Newport Electric Corporation, Northern Indiana Public Service Company, Roseville Electric (CA), Tampa Electric Company, South Jersey Gas Company, Southwest Louisiana Electric Membership Corporation, Southern Indiana Gas and Electric Company, Suffolk County Water Authority (NY), Valley Gas Company and Washington Natural Gas Company

I have provided expert testimony before the Delaware Public Service Commission, the Commonwealth of Kentucky Public Service Commission, the Michigan Public Service Commission, the Indiana Public Service Commission, the Iowa Utilities Board and the Federal Energy Regulatory Commission.

I am a licensed professional engineer in the states of New York and New Jersey.

Q. Do you have your Curriculum Vita available that would list your qualifications and experience?

A. Yes, attached at the end of my testimony is a copy of my Curriculum Vita.

Q. What is the purpose of your testimony?

A. I am sponsoring testimony in the following areas:

1. Support for SLEMCO's request to retain the rate relief afforded by moving from the Cajun to the LA Generating power supply contract;
2. The Purchased Power Adjustment Clause mechanism proposed by the Company;
3. SLEMCO's 1999 unbundled cost of service study; and
4. Modifications to SLEMCO's existing rates to recognize the changeover to the LA Generating contract, roll-in of the proposed retention of savings in moving to the new power supplier, and minor revenue-neutral rate adjustments.

Retention of Savings in Purchased Power Costs

Q. Please describe SLEMCO's proposal for retaining the differential power costs currently included in today's rates relative to the new LA Generating power costs.

A. SLEMCO proposes to retain the 2.3 mill differential created by the adoption of the LA Generating power contract in order to:

1. Increase its investment in needed system improvements,
2. Fund recovery of increased operating costs,
3. Fund preparation for industry restructuring,
4. Provide for an acceptable level of TIER coverage, and
5. Promote rate stability.

With the anticipated industry changes as a result of restructuring, maintaining the revenue difference in the rates will improve the financial position of SLEMCO, thereby allowing better and lower cost access to short- and long-term debt to fund reliability improvement projects. The improved financial position will also provide SLEMCO's consumer-owners with a Company that is better positioned and more able to adapt to the competitive environment. A financially weakened cooperative will be unable to participate effectively in a competitive environment thereby putting consumer-owners interests at risk.

SLEMCO believes that retention of the 2.3 mill savings is not a rate increase per se, but is merely an opportunity which is presented that will allow its consumers to realize the benefits of better service and reliability without having a formal rate increase proceeding. Without this opportunity, the Company would have to seek a rate increase in the very near future.

Q. Please explain how SLEMCO plans to utilize the retained funds.

A. The retained revenues would be utilized to improve system reliability, allow the cooperative to maintain and attract experienced, high quality personnel to operate the system, actions that will allow the Company to compete in an anticipated restructured utility industry. The revenue retention plan would fund construction projects, which have either been deferred due to lack of funds or are necessary to make delivery system improvements to improve reliability and reduce the number of and duration of consumer outages.

In addition, the proposed revenue retention strategy will allow SLEMCO to recover increased operating costs and will result in an improved financial position relative to its target TIER coverage of 1.50 which is expected to be met with the 2.3 mill retention, depending on weather and other factors.

Q. Please describe the improvements in reliability under consideration by SLEMCO relative to the revenue retention request.

A. SLEMCO has an ongoing capital improvement program in place to insure adequate capacity and reliability in accordance to prudent utility practices. This is an ongoing program with an annual cost between 17 million and 21 million dollars.

Q. Please explain the increased operating cost analysis and describe the conclusions relative to the revenue retention strategy.

A. An analysis was prepared by SLEMCO to show the effect of specific cost adjustments on the operations of the Company. This analysis resulted in a test year that is representative of revenue requirements for future operations, assuming that adequate funds are available. The test year used in the analysis was 1999, because it is the most recent calendar year that has complete financial and statistical data available.

Adjustments have been made to the following costs:

A. Payroll increases - to retain and attract quality employees,

B. Health care cost increases – reflecting increased costs for benefits,

C. Pension increases – natural increases relative to plan performance,

D. Transportation cost increases – retiring aging fleet,

E. Property tax increases – due to added assets and increased assessments by local authorities,

F. Improved Right of Way Maintenance Costs – associated with SLEMCO's good faith effort to meet the LPSC's reliability standards,

G. Postage, telephone and office supply expense increases, and

H. Investment in data processing improvements.

SLEMCO further adjusted the analysis to incorporate the effects of weather on revenues – a widely accepted practice. This resulted in a decrease in revenues under normal weather conditions.

Finally, if SLEMCO were to return the revenue differential to consumers, SLEMCO is likely to incur added debt costs to borrow sufficient money to fund the additional costs outlined here.

In summary, SLEMCO is acting responsibly with regard to its consumer-owners by offering its proposal to retain the revenue differential so that its financial situation is improved, its competitive situation is improved and it recover the appropriate level of costs to operate soundly.

Q. Are there other cost adjustments proposed by SLEMCO supporting the revenue retention proposal?

A. Yes, in addition to the increased business operation costs identified above, SLEMCO has undertaken preparation for a restructured utility industry requiring expenditures for implementation planning, system improvements, employee training, and consumer education. The activities undertaken by SLEMCO are those that should be adopted by a well-managed utility in an environment of change and market uncertainty. SLEMCO's proposal to try to recover these investments in the future of the corporation are likely to reduce the transition cost impacts on consumers rates that have occurred in other states upon the introduction of choice. The adjustments associated with investigations of restructuring changes are as follows:

A. Training cost increases – relative to the installation of or development of improved systems in anticipation of restructuring,

B. External support costs – on-going costs to prepare for industry changes and develop appropriate action and implementation plans, renegotiate power contracts, and unbundle rates, and

C. Advertising expense – anticipated expenses needed to assist consumers with industry changes.

Q. Please discuss the impact on TIER of the proposed retention proposal.

A. Cooperatives are expected to maintain a TIER ratio imposed by its RUS contract financing requirements. Should a cooperative fail to maintain the standards, further financing arrangements are provided with less advantageous interest rates which act to increase the overall cost of service to consumers. Regulatory objectives relative to cooperatives should strive, as they do with investor-owned utilities, to allow the Company to succeed financially in order to protect the interests of its owners, in this case the consumers of the cooperative. SLEMCO's proposal will result in a more acceptable TIER coverage, assuming no further increase in costs and fairly normal weather conditions. Providing the opportunity for SLEMCO to manage its business operations well enough to support adequate TIER coverage financially benefits the consumer-owners and the community through increased opportunity for jobs, stable rates and corporate support and investment in local issues.

Q. Please address the issue of rate stability.

A. SLEMCO's proposal moderates the rate impacts for its consumer-owners by keeping the rates the same rather than offering a reduction for some period of time, followed by a rate increase necessary to address the issues raised here. Also, since the proposed 2.3 mill retention is being rolled into rates along with a minor rate realignment proposed in this proceeding it is least disruptive to SLEMCO's consumers and will minimize transition cost increases when customer choice begins.

Q. Please describe the details surrounding the cost adjustments.

A. The 1999 pro forma test year with adjustments, the detail of adjustments and the 1999 pro forma cash requirements analysis are attached to this testimony as Exhibits B-5 to B-7.

Power Cost Adjustment Clause Mechanism

Q. Please describe the Company's proposed Power Cost Adjustment Clause (PCA) mechanism.

A. The PCA is designed to recover all purchased power costs from SLEMCO's supplier, Louisiana Generating. The proposed clause is set forth in Exhibit D-1. It includes separate mechanisms for the recovery of fuel and non-fuel costs.

Q. How are fuel costs recovered in the PCA Clause?

A. Fuel costs are considered to be all costs labeled as 'fuel' on the Louisiana Generating bill. The recovery of fuel costs in the PCA is similar to the Company's existing fuel adjustment calculation, except that instead of computing a loss factor, fuel costs in the prior month are divided by sales in the prior month. This change was proposed in order to simplify the computation and result in a more accurate determination of the monthly adjustment factor. As in the present calculation, any over- or under-collections through the prior month are divided by kWh sales for the most recent 12-month period. The monthly fuel adjustment factor is then applied to all customer class based on energy sales in the next month.

Q. What is included in non-fuel costs?

A. Non-fuel includes the remaining costs under the Louisiana Generating contract not labeled as fuel. These include:

1. Standard Demand Charges;
2. Variable O&M Charges;
3. Hydro Charges;
4. Transmission Charges;
5. Facilities Charges;
6. Incentive Charges and Credits;
7. Energy Credits; and
8. Urban Territory Credit.

Q. How are these costs proposed to be recovered in the PCA?

A. The non-fuel recovery mechanism consists of two components:

1. A monthly base component; and
2. A monthly adjustment factor.

Q. Please describe the base component?

The base component is reset in October of each year and applied in each of the following 12 months beginning in November. This is in accord with the Louisiana Generating contract, which provides that the billing demand in each summer month, May through September, be based on the maximum of SLEMCO's substation demands in the month and that the summer month with the maximum demand be the basis for billing during the remaining seven months, October through April.

The base component will be set at a different level for each customer class. In computing the base component for each class, charges such as the Standard Demand Charges, the largest non-fuel cost component, are based on an estimate of the relative contribution of the class to the total ratchet during the prior summer. Other non-fuel components are allocated to classes on factors that are appropriate to the type of cost and the load profile of class during the past 12 months.

In addition, the base component of the PCA provides for recovery of non-fuel costs in any combination of energy-related or demand-related charges that are appropriate to the class. For example, for non-demand metered consumers recovery must be accomplished on a kWh sales basis. For larger demand-metered customers, base non-fuel costs may be split between demand and energy components.

The October computation for the total base non-fuel amount to be recovered is based on projected changes in contract costs over the next twelve months, and applied to SLEMCO's billing determinants for the most recent 12-month period.

Q. Why is it important to compute a separate non-fuel base value for each rate class?

A. The ability to set a non-fuel base value for each rate class is a critical feature of the proposed PCC. By developing individual class non-fuel base amounts and recovering these costs through a combination of energy and demand charges, SLEMCO is effectively able to recognize differences in class and individual customer load profiles, which is a benefit to all parties. That is, power supply rates that reasonably reflect the fixed and variable cost causation components:

1. Benefits consumers by reducing both interclass and intraclass cross-subsidies;
2. Allows SLEMCO to remain competitive in an open access environment; and
3. Protects Louisiana Generating against cream-skimming by other power suppliers.

Q. How does the monthly non-fuel adjustment factor work?

A. The monthly non-fuel adjustment factor works in much the same way as the monthly fuel adjustment factor. That is, it acts to true-up revenues collected in the prior month from the non-fuel base charge against non-fuel billing from Louisiana Generating in that month. As in the fuel adjustment computation, the difference in non-fuel recovery is added to the cumulative over- or under-recovery through the second preceding month. The total over- or under-recovery is then divided by historical total kWh sales for the Company in the preceding 12-months and applied to kWh sales in the following month. This factor is computed on a total Company basis and applied equally to each customer class on energy sales.

Cost of Service

Q. Have you performed a cost of service study for SLEMCO?

A. Yes, I have performed a fully-allocated unbundled cost of service study for the 12-months ended December 1999. The study was based on the unaudited results of operations for 1999 and does not contain any pro forma, annualization or normalization adjustments.

Also, this study is an update of a recent cost of service study that was undertaken for the test-year 1997, in response to LPSC Order No. U-21453, and filed with this Commission last year. The 1997 study was based on in-depth and extensive analyses of individual accounts, system configuration and operation and class demand relationships. This study incorporates many of the pertinent analyses from the previous cost study and includes updated analyses where appropriate.

The customer classes in the study are defined by the basic rate schedules of the Company including the related riders. The only exceptions were to separately cost two riders. One is the Experimental Economic Development Service (EEDS) rate, which is a rider to Rate 14. The other is SLEMCO's off-peak Time-of-Day rate (Rate 19) which is a rider to Rate 09.

Q. What is an unbundled cost of service study?

A. An unbundled cost of service study determines the cost of service by customer class for each step involved in the process of generating, transmitting, distributing and billing for electricity. In preparing for a restructured market environment it is necessary to unbundle the utility's books, rates and consumers bills. An unbundled cost of service study plays a key role in this process.

Q. How is the cost of service study structured?

A. The cost of service study uses the traditional three-step approach of functionalization, classification and allocation, as this is the most suitable method for costing unbundled cost components. A detailed discussion of each of these steps and the methodologies used are contained in the Report section of the study, which is included in Exhibit C-1.

Q. What do the study results show?

A. There are several results. Rate of return on rate base by customer class is a commonly-used measure of the adequacy of the rates that were in effect during the test-year. Rates of return for SLEMCO's classes are summarized on page 1 of 13 in the Allocation section of the study. For the test-year, SLEMCO had an overall rate of return of 2.87 percent. Classes having a lower than overall Company return may be said to be receiving a subsidy from classes with higher rates of return.

Other cost study results are contained in the Unit Cost section. Page 1 of 16 develops the revenue requirement by customer class based on a target rate of return criterion for each class. By setting each class at the overall return the new class revenue requirement is developed, along with the amount and percent increase in rates needed to achieve that rate of return.

Page 13 of 16 shows the total unbundled revenue requirement for each class at the specified target rate of return. Pages 14 through 16 show the unbundled unit costs by rate class at the target rate of return. These unit costs are expressed in terms of \$/kWh, \$/kW and \$/customer/month, as appropriate to nature of the individual function.

Q. How were the cost of service study results utilized?

A. As mentioned earlier, SLEMCO is proposing a minor rate realignment. The earned rates of return on rate base served as a guide as to which rates should be adjusted upward or downward. In addition, the Unit Costs section developed purchased power costs by customer class. This served as the basis for "mapping" power supply costs in SLEMCO's present rates, which was a necessary prerequisite for the changeover to Louisiana Generating and the development of the proposed Power Adjustment Clause.

The detailed unbundling of other cost components set forth in the Unit Costs section will become increasingly important as the date for customer choice nears in Louisiana.

Rate Changes

Q. What is the nature of the changes to rates that is being proposed?

A. Changes to SLEMCO's rates are being proposed in this proceeding:

1. To extract Cajun power supply costs from SLEMCO's present base rates for recovery through the proposed PCA Clause;
2. To roll the proposed 2.3 mill retention into base rates; and
3. To implement a minor rate realignment in order to bring rates into closer conformance with the cost of service.

Q. Have you prepared an exhibit that shows how you developed the proposed changes to rates?

A. Yes, Exhibit C-2, begins with SLEMCO's present rates and progresses in a step-wise fashion to show the changes that were made in order to arrive at the rates being proposed.

Q. Please describe how you extracted Cajun's purchased power costs from the present rates.

A. The separation of SLEMCO's existing rates between distribution and purchased power costs is set forth in columns (C) through (H) of the exhibit. The starting point was to state the total amount of purchased power costs and distribution costs in each rate. For Rate 01, purchased power costs (excluding fuel) of $11,031,425 is shown on line 14, column (G). This was obtained from page 13 of the Unit Costs section of the cost of service study by adding lines 1 and 2 for Rate 01. The distribution service amount of $7,128,977 as shown on line 14, column (F) was obtained by subtracting $11,031,425 of non-fuel purchased power costs from the total base rate revenue requirement for Rate 01 of $18,160,402, shown on line 30 of page 13 of the Unit Costs section.

Exhibit C-2, line 7, column (D) shows the portion of Rate 01 rate that will produce the allocated non-fuel purchased power costs. The distribution service portion of Rate 01 was obtained by subtracting the purchased power component from the present rate structure. It should be noted that the slight difference in the revenue adjustment factors for purchased power vs. distribution service is due to rounding to five decimal places.

The same procedure was used to separate purchased power from distribution service for each of SLEMCO's other rates.

Q. How did you roll in the proposed 2.3 mill/kWh retention?

A. The treatment accorded the 2.3 mill/kWh retention is shown in columns (I) and (J) of Exhibit C-2. Since the $/kWh savings amount was computed at the generation level, it was increased by 6 percent losses before applying it to class energy sales according to the expression $0.00230 / (1-.06), or $0.00245. This figure was added to the energy component of all of SLEMCO's rates, with the exception of Rates 12, 14 and 45, for which the assignment was varied in an effort to achieve a better alignment of rates with costs.

Q. Were other adjustments made to rates?

A. Yes, columns (K) and (L) of Exhibit C-2 set forth the process used to implement a minor revenue-neutral revenue allocation.

Rate 05 had a modest negative rate of return in the cost of service study. Energy charges in this rate were increased slightly to bring the rate of return into closer alignment with that of Rate 01. In addition, the winter discount in the second energy block was reduced from $0.010 to $0.005 to recognize that part of the original discount was attributable to power supply costs which would no longer be a part of SLEMCO's base rates.

SLEMCO's two seasonal rates, Rate 09 (Seasonal Farm) and Rate 10 (Seasonal Commercial) were assigned minor increases of $0.00010/kWh and $0.00201/kWh, respectively. Rate 09 has traditionally earned a negative rate of return and a significant increase would be necessary in order to bring the rate of return up to an appropriate level. The Company is therefore proposing to close this rate to new customers. Rate 10, which is marginally profitable, will remain open.

The cost study shows that SLEMCO's commercial and industrial rates, Rate 11 (Small Commercial), Rate 12 (Commercial & Industrial), Rate 14 (Industrial) and Rate 45 (EEDS) tend to have progressively higher load factors and lower unit cost of service. Minor margin reallocations were made to these classes in order to bring them closer to their cost of service. This was accomplished by increasing energy charges in Rates 11 and 14 and decreasing energy charges in Rates 12 and 45.

A slight increase was also assigned to Rate 00 (Security Lighting).

Q. Have you prepared a chart that shows a comparison of the rates of return under the present and the proposed rates?

A. Yes, the table below shows the rates of return under SLEMCO's present and proposed rates. As a result of the shifting of margins between classes there is less variance in rates of return, as well as in the index for the class as measured by the class rate of return divided by the overall rate of return. The changes proposed in this proceeding represent only a first step in moving towards a restructured environment.

	Rates of Return & Index			
	Present Rates		Proposed Rates	
Class	ROR	Index	ROR	Index
01 Residential	3.49%	1.21	5.77%	1.15
02 GS	4.63%	1.61	6.34%	1.26
05 Electriconomy	-0.31%	-0.11	2.20%	0.44
09 Seasonal Farm	-11.75%	-4.09	-11.30%	-2.24
10 Seasonal Commercial	2.32%	0.81	4.24%	0.84
11 Small Commercial	5.35%	1.86	7.98%	1.58
12 C&I	7.51%	2.61	8.02%	1.59
14 Industrial	14.15%	4.93	17.04%	3.38
15 Street Lighting	-9.61%	-3.35	-9.61%	-1.91
19 Time-of-Day	63.05%	21.95	68.04%	13.51
45 EEDS	19.67%	6.85	13.60%	2.70
00 Security Lighting	21.80%	7.59	23.58%	4.68
Overall	2.87%	1.00	5.04%	1.00

Q. Does this conclude your testimony?

A. Yes, it does.

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT, R.S.N.S. 1989, C.380, as amended	)	
- and -	)	NSUARB – P-882
IN THE MATTER OF an Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations	)	

Evidence of

ROBERT D. GRENEMAN

On behalf of

HALIFAX REGIONAL MUNICIPALITY

October 2005

Shaw™ Stone & Webster Management Consultants, Inc.

Stone & Webster Management Consultants, Inc.

One Penn Plaza
New York, NY 10119

Tel 212-290-7029
Fax 212-658-9109

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EVIDENCE OF ROBERT D. GRENEMAN

Q1. What is your name, affiliation and business address.

A1. My name is Robert D. Greneman. I am an Associate Director with the firm of Stone & Webster Management Consultants, Inc. My business address is 1 Penn Plaza, New York, NY 10119

Q2. Please provide your educational background and a profile of your experience.

A2. I graduated from the City College of New York in 1970 with a Bachelor of electrical Engineering. I have also done graduate work at City College From 1973 through 1978 I was employed by Alan J. Schultz, Consulting Engineer (later Casazza, Schultz & Associates), a firm that specialized in economic studies and rate work for electric, gas and water utilities. In 1978 I joined Stone & Webster, where, as a consultant I assisted utility companies in rate and regulatory matters. From 1983 to 1986 I was employed by the Brooklyn Union Gas Company in the Rate and Regulatory Department where I was responsible for conducting the Company's cost of service studies, rate design and the review of gas purchase contracts. In 1986 I rejoined Stone & Webster as an executive consultant in the Rate and Regulatory Services Department.

I have prepared cost of service and rate design studies for clients including:

Canada:
Centra Gas British Columbia, Centra Gas Manitoba, Inc., Gaz Metropolitan, Inc. (Montreal), ICG Utilities (Toronto), Newfoundland and Labrador Hydro, and Winnipeg Hydro

U.S. and Other:
Alpena Power Company (MI), Barbados Light & Power Company, Ltd., Blackstone Valley Electric Company, Brockton Edison Company, Central Illinois Light Company, Chesapeake Utilities Corporation, China Light & Power Company, Ltd. (Hong Kong), Citizens Utilities Company, City of Westfield, MA, Colorado Electric Company, Commonwealth Edison Company, Consolidated Edison Company of New York, Dayton Power & Light Company, Delmarva Power & Light Company, Delta Natural Gas Company, Edison Sault Electric Company, El Paso Electric Company, Energy Services of Pensacola, Equitable Gas Company, Fall River Electric Light Company, Florida Public Utilities Company, Gas del Estado (Buenos Aires), Green Mountain Power Company, Guyana Electricity Corporation, Holyoke Department of Gas & Electric (MA), Jamaica Water Supply Company, Lake Superior District Power Company, Louisville Gas & Electric Company, Northern Indiana Public Service Company, Montana-Dakota Utilities Co., Midland Electric Power Cooperative (IA), Newport Electric Corporation, Roseville Electric (CA), Tampa Electric Company, South Jersey Gas Company, Southwest Louisiana Electric Membership Corporation, Southern Indiana Gas and Electric Company, Suffolk County Water Authority (NY), Valley Gas Company (RI), and Washington Natural Gas Company.

I have provided expert testimony before the Delaware Public Service Commission, the Commonwealth of Kentucky Public Service Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the Public Utilities Board of Newfoundland and Labrador and the Federal Energy Regulatory Commission.

I am also a licensed professional engineer in the states of New York and New Jersey.

Q3. What evidence are you presenting in this proceeding?

A3. I am presenting evidence on behalf of the Halifax Regional Municipality (HRM). Stone & Webster Consultants has been retained by HRM to review NSPI's cost of service study (Appendix G) as it pertains to Unmetered service.

Q4. What concerns do you have regarding allocation of costs to the Unmetered service class?

A4. My principal concern is with regard to the weighting factor that NSPI uses to allocate certain customer-related costs to the Unmetered service class.

Q5. Please go on.

A5. The basic factors that are used to allocate customer-related costs are developed in Exhibit 8A (Appendix G, page 38 of 45). In developing factor C-3 (lines 17 through 20), NSPI assigns a weighting factor to the number of customers in each customer class relative to a residential with a weighting of 1.0. The practice of using weighted customers is a commonly-used technique in cost of service studies to allocate certain customer-related costs. Although it is most generally used to allocate costs such as meters and services, NSPI has used weighted customers to allocate billing and customer service-related expenses. My concern is with the weighting of 5.0 that NSPI has assigned to Unmetered service.

Q6. What costs are allocated on factor C-3?

A6. Those customer costs that were allocated on factor C-3 include:

- Billing Services ($4.999 M)[1];
- Call Network ($9.520 M)[2];
- Customer Service Head Office expenses ($5.596 M)[3]; and
- Customer Service Field Expenses ($2.155 M)[4].

According to NSPI, the principal activities that comprise the first three of these functions are enumerated below:

Billing Services includes all operational activities associated with issuing bills to customers, including maintaining the CIS database, collection of billing determinants, bill preparation, quality control, investigation of abnormal bills and bill adjustments where necessary[5].

Call Network The billing inquiries portion of the call network includes balance and due date inquiries; updates to customer files and account information (e.g., name changes or mailing address changes); requests for account history; understanding budget billing, electronic billing and direct deposit payment options; understanding rates; and inquiries or ways to reduce consumption and save money on their bill[6].

[1] Line 11 of Exhibit 6, page 3 of 3 (Appendix G, page 32 of 45).
[2] Line 13 of Exhibit 6, page 3 of 3 (Appendix G, page 32 of 45).
[3] Line 15 of Exhibit 6, page 3 of 3 (Appendix G, page 32 of 45).
[4] Column (3) of Exhibit 6B (Appendix G, page 34 of 45).
[5] NSPI response to HRM IR-4(a) in NSUARB-P-881.
[6] NSPI response to HRM IR-2.

Customer Service Head Office includes development of programs to meet customer service levels, maintaining the external web site, maintaining the customer privacy office, support of the Dispute Resolution Officer and handling escalated customer disputes, processing of payments received from customers and the costs of processing customer payments from external remote payment centers such as financial institutions[7].

Q7. Has NSPI adequately supported its assignment of a weighting factor of 5.0 for Unmetered service in its development of factor C-3?

A7. NSPI's principal support for the weighting factor of 5.0 for the Unmetered class is that the class is commercial in nature[8]. This factor was developed by an outside consultant in 1975 and NSPI has since never performed any studies to validate it[9]. In this regard, I note that the Small Commercial class is also commercial in nature, but NSPI assigned a weighting factor of 1.0 to that class.

Q8. Why do you believe that the use of this weighting factor is inappropriate for the Unmetered class?

A8. There are a couple of aspects to my concern. One pertains to the manner in which "customers" are represented in factor C-3. That is, for customer classes other than Unmetered, NSPI uses the number of customers. However, for Unmetered, NSPI uses the number of "accounts"[10]. There is an important distinction.

Customers are discrete entities in the sense that they have individual consumption patterns and each causes the utility to perform specific activities such as initiation of service activities including securing service deposits, performing credit checks as well as ongoing activities such as

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[7] NSPI response to HRM IR-4(b) in NSUARB-P-881.
[8] NSPI responses to HRM IR-2(a) and HRM IR-2 in NSUARB-P-881.
[9] NSPI response to HRM IR-19(d).
[10] NSPI response to HRM IR-23(a)(iii).

determination of billing determinants and handling billing and service complaints and inquiries. In cost of service there is a recognized relationship between the number of customers and cost causation. A weighting factor is often used to further differentiate the level of these activities among classes. The weighting factor for each class needs to reflect cost causation for that class relative to other classes.

However, the term *customer* for the Unmetered class does not have the same cost causation relationship as it does for the other customer classes. NSPI has no specific attributes that it applies to define a customer within the Unmetered class. In addition, NSPI has indicated that no more specific relationships exist in terms of cost causation between the manner in which it defines an unmetered lighting customer such as HRM, as opposed to, e.g., grouping every 15 lights in a row as a customer, or grouping lights by geographical location[11].

Accounts, as they pertain to the Unmetered class are equally nebulous with respect to any relationship to cost causation. Each customer may have several accounts[12]. NSPI suggests that accounts may be started for a number of different reasons[13], including:

- Connection requests from a variety of different people who may not represent themselves as acting on behalf of the same customer or they may use a slightly different name or abbreviation for the name.

- Amalgamations may take place which merge entities which were previously individual customers; and

[11] NSPI response to HRM IR-4(c).
[12] NSPI response to HRM IR-23(b).
[13] NSPI response to HRM IR-22(b).

- Entities that previously existed as one customer may sell a location and require a new customer identifier which may not be immediately apparent.

In addition, NSPI has confirmed that many accounts have only a few fixtures associated with them[14].

In developing its factor C-3, NSPI has used accounts for the Unmetered class as a surrogate for customers. However, as just discussed, accounts do not conceptually equate with customers as there is no intrinsic relationship to cost causation as there is for customers in the other classes.

NSPI has gone one step further by weighting Unmetered accounts using a weighting of 5.0. However, 5.0 times a measure which is unrelated to cost causation is itself unrelated to cost causation.

Q9. Are you suggesting that the use of accounts as a surrogate for customers in factor C-3 is conceptually flawed, but the weighting factor of 5.0 is appropriate for the Unmetered class?

A9. No. It is my contention that lighting fixtures that sit on top of poles month after month and year after year, and have virtually the same ongoing billing determinants, simply do not require the same level of customer service as, e.g., residential customers. A weighting factor of 1.0 or less is more appropriate as factor C-3. Except for Customer Service Field Expenses, which may require occasional field visits, the expenses in factor C-3 basically reflect costs associated with a general office accounting function. It should be kept in mind that the overwhelming majority of field expenses associated with inspection and maintenance of fixtures, are allocated separately in the distribution function. It would therefore be

[14] NSPI response to HRM IR-17.

inappropriate to rationalize the weighting for this factor based on the physical dispersion of lighting fixtures within NSPI's service territory.

I have reviewed numerous responses by NSPI to HRM Information Requests regarding support for a 5.0 weighting to Unmetered service in factor C-3. Many responses have been elusive and others were referred to previous responses. It is my view that NSPI has not adequately provided support for a weighting factor greater than 1.0 based on factors related to cost causation.

- NSPI indicates that in its judgment, customer service related activity levels associated with multiple unmetered fixtures on the same bill is greater than that for individual residential customers[15]. However, NSPI did not provide any details or examples.

- In response to an HRM request to explain the rationale for assigning a weighting factor of 1.0 in factor C-3 to Small Commercial in light of the fact that NSPI has argued that classes that are commercial in nature should be assigned a weighting factor of 1.0, NSPI has responded that the Small General class is similar to residential in the context being discussed. The power and energy component of unmetered rates are set using the Miscellaneous Small Loads tariff which are derived from the General Tariff[16]. I do not see any relevance of this response to the weightings used in factor C-3, which deals with customer-related expenses.

- HRM asked, with respect to NSPI's position that a single unmetered customer may be billed for several types of lighting fixtures on the same bill, which takes more time relative to residential. To what

[15] NSPI response to HRM IR-18(a).
[16] NSPI response to HRM IR-18(b)(ii).

extent is it true that this is a virtually non-recurring activity? Why does NSPI claim that this takes five times more effort than setting up a residential customer for which a myriad of data needs to be obtained as well as a credit check and for which there is a regular pattern of move-ins and move-outs?[17]

NSPI responded that this statement would be true if this function is looked at in isolation specific to only one customer. However, within the Unmetered class, continuous changes are made to customer accounts for new installations, removals and replacements which incur ongoing operating costs to administer these types of inquires and billing adjustments.

My observation is that, as posed in the question, this is true for residential customers as well, as those customers have a regular pattern of move-ins and move outs as well as shut-off of service for non-payment. It should be kept in mind that even if NSPI can demonstrate additional cost for keeping track of lighting fixtures, it does not summarily affect the other activities that are included in factor C-3.

- HRM asked how many bill inquiries were received in total during 2004? How many of the total bill inquiries during 2004 pertained to unmetered lighting customers? Please provide a chart showing the breakdown of total bill inquiries by type of customer account.[18]

  NSPI responded that the 110,000 billing inquiries referenced involve a variety of customer interactions pertaining to their bill including: balance and due date inquiries; updates to customer files and account

[17] HRM IR-2(a)
[18] HRM-IR-2(d).

information (e.g., name changes or mailing address changes); requests for account history; understanding budget billing, electronic billing and direct deposit payment options; understanding rates; and ways to reduce consumption and save money on their bill.

However, when HRM asked in a follow-up question to confirm that these activities as they pertain to the Unmetered class are virtually nil, NSPI responded that the level of detail required does not exist.

In actual practice, except in respect of burnt out or damaged lights, HRM has minimal interaction with NSPI. In fact, HRM and the Nova Scotia Department of Public Works and Transportation (PWT) do a great deal of work internally with respect to street lighting accounts and required maintenance and forward the results to NSPI. This lightens the load of NSPI significantly. Examples are provided below.

- PWT indicated that the province rarely deletes lighting. Lighting additions are typically done by tendered paving contractors, who install underground power, poles and fixtures which are then turned over for NSPI ownership and maintenance.

- Some corporate customers are creating front end customer service efficiencies for NSPI. PWT typically gives NSPI a list of lights that need to be fixed once per month via direct contact with NSPI field planners. The call centre is never used.

- HRM indicates that since October 2002 they have been using a new software program to generate work orders for new street light installations and sending this information to NSPI via email and letter.

- HRM indicates that street and traffic lights in the Unmetered rate have not generated any other occasions to contact NSPI regarding billing issues. Billing concerns are related to buildings with new accounts and outstanding accounts that HRM is unaware of, which occasions contact approximately three times per month.

My overall observation is that NSPI has not provided adequate support for its assignment of a weighting of 5.0 to the Unmetered class based on factors related to cost causation. This weighting is too high from a bottom-up viewpoint as well as a top-down viewpoint. For example, NSPI assigns a weighting factor of 5.0 to 8,950 accounts, resulting in 44,750 weighted accounts. This translates to Unmetered being responsible for 7.77 percent[19] of approximately $22.270 M of billing, customer service and call center expenses that are dependent on factor C-3, of which $1.730 million per year is allocated to Unmetered service. It is difficult to rationalize such a great expense for billing, customer service and call center for Unmetered, especially in light of the fact that this excludes all rate base related costs for these functions.

The 5.0 weighting factor was recommended by a consultant approximately 30 years ago and NSPI has not validated it since. I recommend that the 5.0 weighting be revised to a 1.0 weighting based on the lack of adequate cost-related support. **Table 1**, below, shows the effect on the Unmetered class as the result of my recommendation.

[19] Exhibit 8A, column (10), line (20) (Appendix G, page 38 of 45).

Table 1: Factor C-3. Unmetered Weighting of 1.0 versus 5.0

	Expenses Allocated on Factor C-3				
	Billing Services	Call Network	Customer Service H.O. Expenses	Customer Service Field Expenses	Total
C-3 Allocated Expenses	$ 4,999,000	$ 9,520,000	$ 5,596,000	$ 2,155,000	$ 22,270,000
Unmetered Wtg Factor of 5.0					
Percent	7.773%	7.773%	7.773%	7.773%	
Amount	$ 388,572	$ 739,990	$ 434,977	$ 167,508	$ 1,731,047
Unmetered Wtg Factor of 1.0					
Percent	1.658%	1.658%	1.658%	1.658%	
Amount	$ 82,864	$ 157,805	$ 92,760	$ 35,722	$ 369,151
Difference	$ (305,708)	$ (582,185)	$ (342,217)	$ (131,787)	$ (1,361,896)

Q10. Do you have any other observations or recommendations regarding the development of factor C-3?

A10. Yes. As I have referred to earlier, the weighting factor format is commonly used to allocate certain customer-related costs such as meters and services. In such applications, and as NSPI has used factor C-3 to apply to billing and customer service-related expenses, rounded weightings are often used, e.g., Residential: 1.0; General: 5.0; Medium Industrial: 25.0; Large Industrial: 100.0. Such an assignment of weightings for each class typically involves a process in which high and low weightings are assigned to certain classes and thumbnail judgment is used to fit in weightings for the remaining classes. These thumbnail weightings for the larger customer classes are generally not challenged since customer costs are typically very low in comparison to their total cost of service.

Cost of service, however, can be generalized or very specific when it needs to be. Additional specificity is appropriate when significant dollars are at stake for a class or when customers challenge the allocation as being unreasonably high in light of the activities involved. Such is the case for Unmetered service. Nearly ten percent[20] of the cost of service for this class is customer-related – the greater portion of which is dependent on factor C-3.

It is too simplistic to group, and virtually impossible to support, the myriad of activities that are included in customer service, billing services and call network under this single weighted factor, especially for a utility the size of NSPI. I recommend that NSPI either expand its cost of service study to provide greater allocation flexibility in being able to address the individual activities or to perform a subsidiary analysis that addresses principal activities individually and roll the results for the Unmetered class into a revised weighting.

Q11. How have you allocated billing and customer service-related expenses in the cost of service studies that you have performed?

A11. Prior to developing allocation factors for billing and customer-related expenses, I interview utility personnel responsible for each activity. I then quantify and directly assign those costs that are unique to certain customer classes, such as, manual billing for certain industrial customers, and administrative costs associated with gas transportation customers. The balance of billing and customer-service-related expenses are allocated on number of customers, including street lighting. A weighting factor of 1.0 is implied.

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[20] Exhibit 10 (Appendix G, page 44 of 45): [column (4), line (9)] / [column(5) line 9] = 9.7 percent.

I am also familiar with the methodology employed by Newfoundland and Labrador Hydro. Their study, which was done in-house, also allocates billing and customer service-related expenses on the unweighted number of customers, including street lighting. (Weighting factors were used for meters and services.)

In addition, I have examined the cost of service study for Manitoba Hydro. In the Manitoba study numerous customer-related factors are developed; however, the exact formulation of a number of the factors is uncertain as they are simply portrayed as values. Nonetheless, I compared the magnitudes of the factors for Area and Roadway Lighting with Residential for the allocation of both Customer Service-General and Customer Accounting factors, and observe that in each case the proportion applicable to lighting is significantly less than residential than if the allocation were done on a strictly customer basis. In one case Roadway Lighting was explicitly weighted one-tenth.

Q12. Do you have any other concerns with respect to allocation of customer-related costs?

A12. Yes. In response to HRM-13 in NSUARB-P-881, NSPI removed the allocation of direct meter reading expenses and equipment to the Unmetered class. However, there are still costs associated with the meter reading function that are allocated to Unmetered[21]. These are the indirect capital costs including vehicles and general plant such as buildings, computers, and the like, which attract depreciation, interest, return and taxes. If NSPI had prepared a fully unbundled cost of service study, the functionalization of all expense and plant-related costs, including administrative and general expenses and general plant associated with each unbundled function could be readily identifiable. I recommend that

[21] NSPI response to HRM IR-15(b) in NSUARB-P-881.

NSPI identify these associated meter reading costs in a subsidiary analysis and exclude them from the allocation to the Unmetered class.

Q13. Do you have any other concerns with respect to allocation of customer-related costs?

A13. I have no specific concerns at this time other than to note that the NSPI winter system peak may be shifting from early evening to the start of the weekday workday[22]. For the forecast test year the light-sensitive portion of Unmetered service was reported as effectively being on in the three winter months, December through February. However, for two of the three most recent winter months (January and February 2005) NSPI had its system peak at the hour ending 9 AM. At that hour the light sensitive portion of Unmetered was off. To the extent that this trend in shift of the time of the NSPI winter peak is confirmed, it should be reflected in the forecast coincident system demands for the Unmetered class at NSPI's next GRA.

Q14. Do you have any comments with respect to rate design for the Unmetered class?

A14. Yes. I have experienced difficulty trying to reconcile NSPI's proposed rate design for the Unmetered class with its cost of service. I subsequently learned through a data request that NSPI based its rate design on a 1977 study and that since that time, increases have been applied across-the-board to the power, energy, maintenance and capital components of street lighting rates[23]. NSPI has indicated that the study was outdated and needed to be updated[24], but this has not been done for the current proceeding. I recommend that the updated study be completed in time for NSPI's next GRA.

[22] Based on a review of the time of NSPI winter system peaks as provided in response to HRM IR-6 in NSUARB-P881 and HRM IR-31 in this proceeding.
[23] NSPI response to HRM IR-10 in NSUARB-P-881.
[24] NSPI response to HRM IR-19 in NSUARB-P-881.

Q15. Would you please summarize your observations and recommendations?

A15. Yes. I would summarize my observations and recommendations as follows:

- NSPI's use of accounts as a surrogate for customers in factor C-3 is conceptually flawed, as the number of accounts is not related to cost causation. A weighting factor of 5.0 for the Unmetered class times the number of accounts is therefore also not related to cost causation.

- It is unreasonable, in my view, that billing, customer service, and call center expenses for Unmetered accounts are greater than for residential accounts. The weighting factor for Unmetered should not exceed 1.0.

- Cost of service requires that allocations be related to factors based on cost causation. NSPI has not adequately supported its use of a weighting to the Unmetered class of 5.0 in factor C-3.

- NSPI should undertake a more detailed analysis of the activities that are included in factor C-3. I recommend that until such analysis is completed, this Board direct NSPI to set the weighting to the Unmetered class in factor C-3 from 5.0 to 1.0, beginning in this proceeding.

- NSPI should identify the portion of rate base for vehicles and general plant that are associated with the meter reading function and remove the attendant interest, return, taxes and depreciation from its allocation to the Unmetered class.

- NSPI should update its rate design analysis, which is nearly 30 years old, prior to its next GRA.

Q16. Does this conclude your testimony?

A16. Yes.

Petitioner's Exhibit RDG-1

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE CO. FOR APPROVAL OF A PURCHASED POWER AND TRANSMISSION TRACKER MECHANISM TO TRACK THE COSTS OF PURCHASED POWER TO MEET PETITIONER'S RETAIL ELECTRIC LOAD REQUIREMENTS AND CHARGES IMPOSED ON PETITIONER BY MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC. AND GRIDAMERICA LLC.	)	Cause No. 42658

PREPARED DIRECT TESTIMONY OF ROBERT D. GRENEMAN ON BEHALF OF NORTHERN INDIANA PUBLIC SERVICE COMPANY

Daniel W. McGill, Atty No. 9489-49
Claudia J. Earls, Atty No. 8468-49
Barnes & Thornburg LLP
11 S. Meridian St.
Indianapolis, IN 46204
Telephone: (317) 231-7229
Fax: (317) 231-7433
Email: dmcgill@btlaw.com

Attorneys for Petitioner
NORTHERN INDIANA
PUBLIC SERVICE COMPANY

August 6, 2004

PREPARED DIRECT TESTIMONY OF ROBERT D. GRENEMAN

Q: Please state your name, occupation and business address.

A: My name is Robert D. Greneman. I am an Associate Director in the Markets, Finance and Regulation group with the firm of Stone & Webster Consultants, Inc., Penn Plaza, New York, NY 10119.

Q: Please describe your educational and professional background.

A: I graduated in 1979 from the City College of New York ("CCNY"), with a Bachelor of Engineering degree in Electrical Engineering. I have also done graduate work at CCNY. From 1973 through 1978 I was employed by Alan J. Schultz, Consulting Engineer (later Casazza, Schultz & Associates), a firm that specialized in economic studies and rate work for electric, gas and water utilities. As an associate engineer my responsibilities included performing cost of service studies, rate design, load forecasting, depreciation studies, economic feasibility studies, valuation studies, plant inspections and the review of power contracts. In 1978 I joined Stone & Webster, where, as a consultant I have continued to assist utility companies in rate and regulatory matters. From 1983 to 1986 I was employed by the Brooklyn Union Gas Company in the Rate & Regulatory Department, where I was responsible for conducting the Company's cost of service studies, rate design and the review of gas purchase contracts. In 1986 I rejoined Stone & Webster as an executive consultant in the Rate and Regulatory Service Department. I am a licensed professional engineer in the states of New York and New Jersey.

Q: Have you performed many cost of service studies?

A: Yes. I have prepared numerous cost of service and rate design studies many for gas and electric utilities, including Alpena Power Company, (MI), Barbados Light & Power Company, Ltd., Blackstone Valley Electric Company, Brockton Edison Company, Centra Gas British Columbia, Central Illinois Light Company, Chesapeake Utilities Corporation, China Light & Power Company, Ltd. (Hong Kong), Citizens Utilities Company, City of Westfield, MA, Colorado Electric Company, Commonwealth Edison Company, Consolidated Edison Company of New York, Dayton Power & Light Company, Delmarva Power & Light Company, Delta Natural Gas Company, Edison Sault Electric Company, El Paso Electric Company, Equitable Gas Company, Fall River Electric Light Company, Florida Public Utilities Company, Gas del Estado (Buenos Airs), Gaz Metropolitain, Inc. (Montreal), Green Mountain Power Company, Guyana Electricity Corporation, Holyoke Department of Gas & Electric (MA), ICG Utilities (Toronto), Lake Superior District Power Company, Louisville Gas & Electric Company, Montana-Dakota Utilities Co., Midland Electric Power Cooperative (IA), Newfoundland & Labrador Hydro, Newport Electric Corporation, Roseville Electric (CA), Tampa Electric Company, South Jersey Gas Company, Southwest Louisiana Electric Membership Corporation, Southern Indiana Gas and Electric Company, Suffolk County Water Authority, Valley Gas Company, Washington Natural Gas Company, Winnipeg Hydro and Northern Indiana Public Service Company ("NIPSCO").

Q: Have you testified before any Commissions or other regulatory bodies?

A: Yes. I have provided expert testimony before the Delaware Public Service Commission, the Commonwealth of Kentucky Public Service Commission, the Public Utilities Board of Newfoundland and Labrador, the Louisiana Public Service Commission, the Michigan Public Service Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board and the Federal Energy Regulatory Commission.

Q: When did you do a cost of service study for NIPSCO?

A: I did a cost of service study for NIPSCO in connection with NIPSCO's recent electric rate investigation, Cause No. 41746 before this Commission. That was a fully-allocated cost of service study, which separated costs between the Company's Indiana jurisdictional business and its non-jurisdictional, or wholesale business and developed the cost of serving each of the Indiana jurisdictional classes of service.

Q: Did you submit testimony and exhibits in Cause No. 41746?

A: Yes, I submitted both testimony and an exhibit showing the results of my cost of service study that summarized operating income, rate base and rates of return earned for each retail class of service. My testimony was submitted in Cause No. 41746, as Respondent's Exhibit RDG-1. The cost of service study that I did was submitted in the form of work papers filed with the Commission. Its ultimate results were shown in Respondent's Exhibit RDG-2 in that case.

Q: What was the test-year you used in that cost of service study?

A: My cost of service study was based on the audited financial results of the Company's electric operations for the 12 months ended December 31, 1999, adjusted for known, fixed and measurable changes occurring within the 12 months ended December 31, 2000. The class demands used in that cost study were based on control area peaks and Company load research data for calendar year 2000, which was used because of abnormal weather conditions in 1999 and more normal weather conditions in 2000.

Q: Please describe the general allocation procedures that you used in preparing your cost of service study in Cause No. 41746.

A: My cost of service study used a three-step approach: functionalization, classification and allocation. Functionalization assigns all plant and expenses to the basic steps involved in the process of producing, transmitting, distributing and billing for electricity. Classification further assigns costs for each function as being demand-, energy- or customer-related. Allocation is the process of apportioning each functionalized and classified cost group to classes of service based on factors related to cost causation. This process was described in more detail in my testimony in Respondent's Exhibit RDG-1 in Cause No. 41746.

Q: How did you allocate purchased power and transmission demand costs to the various customer classes in that cost of service study?

A: The allocation of purchased power and transmission demand costs was based on NIPSCO load research analysis that reported the demand for each class at the time of the control area peak hour for each month during 2000. The peak demand for each class was then increased for losses to reflect the load at the generation level. Demand related purchased power and transmission costs were allocated to each class based on its demand at the time of the control area peak hour for each month during the summer peak period of June through September. This procedure was detailed in the electronic work paper file "Load Data.xls" that accompanied the cost of service study.

Q: Is year 2000 load data reasonable for use in the proposed Purchased Power and Transmission Tracker ("PPTT")?

A: Yes. I looked at a comparison of kWh sales between 2000 and 2003 and although there are some differences in customer classes, overall the results are reasonably consistent.

Q: Is the proposed PPTT then based on the data in your previous study?

A: Yes. However, I have gone one step further to also calculate allocation factors for purchased power and transmission demand costs to customer classes based on the relationship of class demands within calendar quarters.

Q: Please describe how you computed the quarterly class demands.

A: Petitioner's Exhibit RDG-2 shows the portions of the "Load Data.xls" work paper that are pertinent to understanding how the demand allocation factors were developed in the cost of service study.

Petitioner's Exhibit RDG-3, Schedule 1 shows the control area peak by customer class for each month in 2000. This data, the result of NIPSCO's load research program, was the same data that was used to develop the demand factors used in my cost of service study. All demands in this schedule are at the customer's meter.

Petitioner's Exhibit RDG-3, Schedule 2 shows the computation of the average demand by class for each calendar quarter.

Schedule 3 of Petitioner's Exhibit RDG-3 shows how class load at the meter is adjusted for losses to the generation level on a quarter-by-quarter basis. The final class demand factors for both production and transmission are contained in Schedule 4 of this exhibit.

Q: Did you supply those production and transmission related allocations to Cathy Hodges for use in this case?

A: Yes, I supplied her with those allocations.

Q: Does this conclude your Prepared Direct Testimony?

A: Yes, it does.

NORTHERN INDIANA PUBLIC SERVICE COMPANY
DEVELOPMENT OF CLASS COINCIDENT PEAK FACTORS
(Source: Electronic Workpaper "Load Data.xls")

II - BALANCE SALES AND LOSSES WITH KWH GENERATION

		VOLTAGE LEVEL LOSSES (%)					ENERGY LOSS MULTIPLIERS				DEMAND LOSS MULTIPLIERS	
			ADJUSTED									
	AGGREGATE MWH LOAD AT VOLTAGE LEVEL	% BASIS	ADJUSTMENT FACTOR	%	AMOUNT	KWH SALES AT VOLTAGE LEVEL	SIMPLE	CUMULATIVE	EST. RATIO DEMAND TO ENERGY LOSSES	EST. DEMAND LOSSES (%)	SIMPLE	CUMULATIVE
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
VOLTAGE LEVEL (INPUT TO)									0			
TRANSMISSION	18,658,945	1.17%	0.999850	1.17%	218,090	8,904,928	1.0118	1.0118	1.1898	1.39%	1.0141	1.0141
PRIMARY	9,535,926	0.90%	0.999850	0.89%	85,334	1,869,138	1.0090	1.0210	1.1898	1.06%	1.0108	1.0250
SECONDARY	7,581,455	5.13%	0.999850	5.12%	388,491	7,192,964	1.0540	1.0761	1.1898	6.10%	1.0649	1.0916
TOTAL PRODUCTION (KWH) ------>	*18,658,945*	0.0%				17,967,030						
CALCULATED KWH @ GEN. ------>	*18,658,945*	0.0%										
DIFFERENCE ---->	*0*	0.0%										

IV - AVERAGE CLASS CONTRIBUTION TO CONTROL AREA PEAK *(At Meter Based on Load Research)*

	Total Company	Residential Rate 811	G.Cents-Res. Rate 812	G.Cents-MFD Rate 813	G.Cents-Comml Rate 820	GS Rate 821	Comml SH Rate 822	GS Rate 823	GS Large Rate 824	Comml GS Sm. Rate 817	Metel Melting Rate 825	Off-Peak Serv. Rate 826
4 COINCIDENT PEAK AVERAGE	2,879,117	674,453	6,148	2,248	0	290,315	0	265,410	330,977	0	27,983	67,628
LOAD FACTOR	*71.24%*	*47.75%*	*61.74%*	*51.44%*	*0.00%*	*48.25%*	*0.00%*	*62.98%*	*77.28%*	*0.00%*	*106.11%*	*62.83%*
12 COINCIDENT PEAK AVERAGE	2,498,065	467,839	4,991	1,957	1,895	201,083	2,274	213,191	317,706		29,218	59,416
LOAD FACTOR	*82.10%*	*68.84%*	*76.05%*	*59.09%*	*83.58%*	*69.66%*	*91.84%*	*78.41%*	*80.51%*	*0.00%*	*101.62%*	*71.52%*
Selected Methodology -->	2,879,117	674,453	6,148	2,248	-	290,315	-	265,410	330,977	-	27,983	67,628

NORTHERN INDIANA PUBLIC SERVICE COMPANY
DEVELOPMENT OF CLASS COINCIDENT PEAK FACTORS
(Source: Electronic Workpaper "Load Data.xls")

il - BALANCE SALES AND LOSSES WITH KWH GENERATION

VOLTAGE LEVEL (INPUT TO)
TRANSMISSION
PRIMARY
SECONDARY

TOTAL PRODUCTION (KWH) ------>
CALCULATED KWH @ GEN. ------>
DIFFERENCE ---->

IV - AVERAGE CLASS CONTRIBUTION TO CONTROL AREA PEAK *(At Meter Based on Load Research)*

	Ind. Pwr Serv. Rate 832	Ind. Pwr Serv. Rate 833	Int. Ind. Pwr S. Rate 836	Muni. Power Rate 841	Indust. Off-Peak Rate 845	Firm Contract Rate 847	Traffic Lighting	Street Lighting	Rate 844 Railroad	Interdept	Total Retail
4 COINCIDENT PEAK AVERAGE	16,435	235,582	69,500	2,931	258,082	255,222	1,130	0	979	3,582	2,508,605
LOAD FACTOR	*25.94%*	*100.79%*	*141.39%*	*103.18%*	*98.44%*	*69.60%*	*101.27%*	*0.00%*	*177.35%*	*130.89%*	*69.99%*
12 COINCIDENT PEAK AVERAGE	14,539	208,438	82,750	2,859	308,908	298,129	1,145	3,918	1,857	3,560	2,225,674
LOAD FACTOR	*29.32%*	*113.92%*	*118.75%*	*105.78%*	*82.24%*	*59.58%*	*99.92%*	*193.79%*	*93.50%*	*131.70%*	*78.88%*
Selected Methodology -->	16,435	235,582	69,500	2,931	258,082	255,222	1,130		979	3,582	2,508,605

NORTHERN INDIANA PUBLIC SERVICE COMPANY
DEVELOPMENT OF CLASS COINCIDENT PEAK FACTORS
(Source: Electronic Workpaper "Load Data.xls")

VII - COINCIDENT KW BY VOLTAGE LEVEL

	Total Company	Residential Rate 811	G.Cents-Res. Rate 812	G.Cents-MFD Rate 813	G.Cents-Comml Rate 820	GS Rate 821	Comml SH Rate 822	GS Rate 823	GS Large Rate 824	Comml GS Sm. Rate 817	Metel Melting Rate 825	Off-Peak Serv. Rate 826
PRODUCTION	0	0	0	0	0	0	0	0	0	0	0	0
TRANSMISSION	1,043,173	0	0	0	0	552	0	1,486	41,505	0	17,912	1,873
PRIMARY	364,290	0	0	0	0	6,271	0	21,711	133,417	0	9,791	16,001
SECONDARY	1,471,654	674,453	6,148	2,248	0	283,493	0	242,213	156,056	0	280	49,754
TOTAL	2,879,117	674,453	6,148	2,248	0	290,315	0	265,410	330,977	0	27,983	67,628
ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0	0	0

VIII - DISTRIBUTION OF COINCIDENT KW AND LOSSES BY VOLTAGE LEVEL

COINCIDENT KW	Total Company	Rate 811 Base	G.Cents-Res. Rate 812	G.Cents-MFD Rate 813	G.Cents-Comml Rate 820	GS Rate 821	Comml SH Rate 822	GS Rate 823	GS Large Rate 824	Comml GS Sm. Rate 817	Metel Melting Rate 825	Off-Peak Serv. Rate 826
LOAD @ INPUT TO GENERATION	*3,037,700*	*736,212*	*6,711*	*2,454*	*0*	*316,439*	*0*	*288,153*	*349,190*	*0*	*28,506*	*72,611*
LOSS FACTOR		*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*
SALES @ GENERATION	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
LOAD @ INPUT TO TRANSMISSION	*3,037,700*	*736,212*	*6,711*	*2,454*	*0*	*316,439*	*0*	*288,153*	*349,190*	*0*	*28,506*	*72,611*
LOSS FACTOR		*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*
SALES @ TRANSMISSION	*1,043,173*	*0*	*0*	*0*	*0*	*552*	*0*	*1,486*	*41,505*	*0*	*17,912*	*1,873*
LOAD @ INPUT TO PRIMARY	*1,952,282*	*725,973*	*6,618*	*2,420*	*0*	*311,486*	*0*	*282,660*	*302,829*	*0*	*10,198*	*69,728*
LOSS FACTOR		*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*
SALES @ PRIMARY	*364,290*	*0*	*0*	*0*	*0*	*6,271*	*0*	*21,711*	*133,417*	*0*	*9,791*	*16,001*
LOAD @ INPUT TO SECONDARY	*1,567,205*	*718,244*	*6,547*	*2,394*	*0*	*301,899*	*0*	*257,940*	*166,188*	*0*	*298*	*52,984*
LOSS FACTOR		*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*
SALES @ SECONDARY	*1,471,654*	*674,453*	*6,148*	*2,248*	*0*	*283,493*	*0*	*242,213*	*156,056*	*0*	*280*	*49,754*
TOTAL AT METER	2,879,117	674,453	6,148	2,248	0	290,315	0	265,410	330,977	0	27,983	67,628
	0	0	0	0	0	0	0	0	0	0	0	0

NORTHERN INDIANA PUBLIC SERVICE COMPANY
DEVELOPMENT OF CLASS COINCIDENT PEAK FACTORS
(Source: Electronic Workpaper "Load Data.xls")

VII - COINCIDENT KW BY VOLTAGE LEVEL

	Ind. Pwr Serv. Rate 832	Ind. Pwr Serv. Rate 833	Int. Ind. Pwr S. Rate 836	Muni. Power Rate 841	Indust. Off-Peak Rate 845	Firm Contract Rate 847	Traffic Lighting	Street Lighting	Rate 844 Railroad	Interdept	Total Retail
PRODUCTION	0	0	0	0	0	0	0	0	0	0	0
TRANSMISSION	16,435	235,582	69,500	45	258,082	184,449	0	0	0	2,507	829,928
PRIMARY	0	0	0	95	0	18,759	0	0	979	0	207,023
SECONDARY	0	0	0	2,791	0	52,014	1,130	0	0	1,075	1,471,654
TOTAL	16,435	235,582	69,500	2,931	258,082	255,222	1,130	0	979	3,582	2,508,605
ZERO CHECK -->	0	0	0	0	0	0	0	0	0	0	0

VIII - DISTRIBUTION OF COINCIDENT KW AND LOSSES BY VOLTAGE LEVEL

COINCIDENT KW	Ind. Pwr Serv. Rate 832	Ind. Pwr Serv. Rate 833	Int. Ind. Pwr S. Rate 836	Muni. Power Rate 841	Indust. Off-Peak Rate 845	Firm Contract Rate 847	Traffic Lighting	Street Lighting	Rate 844 Railroad	Interdept	Total Retail
LOAD @ INPUT TO GENERATION	*16,667*	*238,904*	*70,480*	*3,190*	*261,722*	*263,055*	*1,233*	*0*	*1,003*	*3,716*	*2,660,246*
LOSS FACTOR	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*
SALES @ GENERATION	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
LOAD @ INPUT TO TRANSMISSION	*16,667*	*238,904*	*70,480*	*3,190*	*261,722*	*263,055*	*1,233*	*0*	*1,003*	*3,716*	*2,660,246*
LOSS FACTOR	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*
SALES @ TRANSMISSION	*16,435*	*235,582*	*69,500*	*45*	*258,082*	*184,449*	*0*	*0*	*0*	*2,507*	*829,928*
LOAD @ INPUT TO PRIMARY	*0*	*0*	*0*	*3,100*	*0*	*74,948*	*1,216*	*0*	*990*	*1,157*	*1,793,322*
LOSS FACTOR	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*
SALES @ PRIMARY	*0*	*0*	*0*	*95*	*0*	*18,759*	*0*	*0*	*979*	*0*	*207,023*
LOAD @ INPUT TO SECONDARY	*0*	*0*	*0*	*2,972*	*0*	*55,391*	*1,203*	*0*	*0*	*1,144*	*1,567,205*
LOSS FACTOR	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*
SALES @ SECONDARY	*0*	*0*	*0*	*2,791*	*0*	*52,014*	*1,130*	*0*	*0*	*1,075*	*1,471,654*
TOTAL AT METER	16,435	235,582	69,500	2,931	258,082	255,222	1,130	0	979	3,582	2,508,605
	0	0	0	0	0	0	0	0	0	0	0

NORTHERN INDIANA PUBLIC SERVICE COMPANY
DEVELOPMENT OF CLASS COINCIDENT PEAK FACTORS
(Source: Electronic Workpaper "Load Data.xls")

XIII - DEVELOPMENT OF ALLOCATION FACTORS

	Total Retail	Rate 811 Base	G.Cents-Res. Rate 812	G.Cents-MFD Rate 813	G.Cents-Comml Rate 820	GS Rate 821	Comml SH Rate 822	GS Rate 823	GS Large Rate 824	Comml GS Sm. Rate 817	Metel Melting Rate 825	Off-Peak Serv. Rate 826
GENERATION												
Average CP @ Generation	2,665,435	736,212	6,711	2,454	0	316,439	0	288,153	349,190	0	28,506	72,611
Adjustments -1	-53,100										-15,000	
Adjustments -2	4,036				564		748					
Adjusted Average CP @ Generation	2,616,371	736,212	6,711	2,454	564	316,439	748	288,153	349,190	0	13,506	72,611
TRANSMISSION LINES & SUBSTAS.												
Average CP @ Transmission	2,665,435	736,212	6,711	2,454	0	316,439	0	288,153	349,190	0	28,506	72,611
Adjustments -1	0											
Adjustments -2	0											
Adjusted Average CP @ Transmissior	3,037,700	736,212	6,711	2,454	0	316,439	0	288,153	349,190	0	28,506	72,611

NORTHERN INDIANA PUBLIC SERVICE COMPANY
DEVELOPMENT OF CLASS COINCIDENT PEAK FACTORS
(Source: Electronic Workpaper "Load Data.xls")

XIII - DEVELOPMENT OF ALLOCATION FACTORS

	Ind. Pwr Serv. Rate 832	Ind. Pwr Serv. Rate 833	int. Ind. Pwr S. Rate 836	Muni. Power Rate 841	Indust. Off-Peak Rate 845	Firm Contract Rate 847	Traffic Lighting	Street Lighting	Rate 844 Railroad	Interdept	Total Retail
GENERATION											
Average CP @ Generation	16,667	238,904	70,480	3,190	261,722	263,055	1,233	0	1,003	3,716	2,660,246
Adjustments -1			-36,000			-6,334					-57,334
Adjustments -2								2,724			4,036
Adjusted Average CP @ Generation	16,667	238,904	34,480	3,190	261,722	256,722	1,233	2,724	1,003	3,716	2,606,948
TRANSMISSION LINES & SUBSTAS.											
Average CP @ Transmission	16,667	238,904	70,480	3,190	261,722	263,055	1,233	0	1,003	3,716	2,660,246
Adjustments -1											0
Adjustments -2											0
Adjusted Average CP @ Transmissior	16,667	238,904	70,480	3,190	261,722	263,055	1,233	0	1,003	3,716	2,660,246

NORTHERN INDIANA PUBLIC SERVICE COMPANY
CONTROL AREA PEAK
(BY RATE CLASS BY MONTH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	12-Month Average	4-Month Average
Rate Class	1/27/2000 @ 2000	2/28/2000 @ 1900	3/10/2000 @ 1000	4/12/2000 @ 900	5/8/2000 @ 1300	6/23/2000 @ 1500	7/27/2000 @ 1400	8/15/2000 @ 1400	9/1/2000 @ 1300	10/2/2000 @ 1600	11/20/2000 @ 1100	12/21/2000 @ 1800		
811-01 & 03	366,340	302,825	195,649	261,844	391,448	503,305	580,531	735,659	754,962	395,858	298,618	469,943	438,082	643,614
811-02	37,301	18,953	29,562	18,923	22,419	25,139	27,992	33,930	36,293	20,732	29,959	55,882	29,757	30,839
812-02	5,302	3,338	3,385	3,122	5,013	5,434	5,512	7,506	6,138	3,074	3,827	8,245	4,991	6,148
813-02	2,362	453	1,650	961	1,474	2,171	2,066	1,883	2,873	1,954	3,092	2,547	1,957	2,248
820	4,379	2,420	3,434	3,378	1,072	-	-	-	-	1,172	2,854	4,027	1,895	-
821	133,850	97,355	171,365	118,846	258,221	276,570	280,727	314,201	289,762	115,920	205,735	150,445	201,083	290,315
822	4,955	1,785	4,916	3,191	2,617	-	-	-	-	1,501	2,961	5,365	2,274	-
823	150,591	151,740	194,240	205,682	223,922	243,209	251,832	302,607	263,991	212,955	186,648	170,880	213,191	265,410
824	284,130	310,170	338,997	329,855	382,537	317,538	338,955	327,104	340,311	275,873	319,862	247,142	317,706	330,977
825	27,656	26,269	34,552	42,741	35,595	25,457	32,364	27,549	26,560	20,361	35,010	16,507	29,218	27,983
826	53,355	53,479	53,626	50,473	63,820	64,202	67,505	69,566	69,237	60,492	54,350	52,886	59,416	67,628
832	9,401	11,034	11,725	9,971	10,986	11,183	20,188	15,073	19,297	19,250	17,446	18,875	14,536	16,435
833	196,827	198,330	187,366	172,785	202,611	219,217	237,644	243,924	241,542	227,396	178,026	195,592	208,438	235,582
836	96,000	96,000	100,000	92,000	77,000	101,000	59,000	59,000	59,000	100,000	80,000	74,000	82,750	69,500
841	3,194	1,505	4,250	2,860	2,514	2,992	2,934	3,144	2,656	2,562	2,510	3,185	2,859	2,931
844	3,659	4,494	1,438	1,695	720	1,288	784	708	1,136	1,589	1,091	3,675	1,857	979
845	375,242	428,126	369,228	336,619	295,880	285,633	249,772	251,450	245,473	291,026	275,098	303,346	308,908	258,082
847	341,676	398,563	386,915	260,896	292,927	227,765	293,166	231,456	268,500	278,405	310,169	287,114	298,129	255,222
Traffic Lights	1,118	1,129	1,122	1,122	1,316	1,130	1,132	1,130	1,129	1,139	1,132	1,146	1,145	1,130
Other Street Lighting	15,685	15,239	-	-	-	-	-	-	-	-	-	16,094	3,918	-
Interdepartmental	2,367	2,823	3,051	3,840	9,466	4,602	3,630	2,808	3,288	2,581	2,830	1,432	3,560	3,582
Total Internal	2,115,392	2,126,028	2,096,470	1,920,805	2,281,558	2,317,836	2,455,734	2,628,698	2,632,149	2,033,841	2,011,217	2,088,327	2,225,671	2,508,604
Wholesale	232,275	199,282	195,136	191,565	227,950	265,772	291,681	337,148	327,448	204,288	225,043	261,112	246,558	305,512
Total Control Area	2,347,667	2,325,310	2,291,606	2,112,370	2,509,508	2,583,608	2,747,415	2,965,846	2,959,597	2,238,129	2,236,260	2,349,439	2,472,230	2,814,116

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COMPUTATION OF QUARTERLY DEMAND FACTORS

Month	Total Retail	Rate 811 Base	G.Cents-Res. Rate 812	G.Cents-MFD Rate 813	G.Cents-Comml Rate 820	GS Rate 821	Comml SH Rate 822	GS Rate 823	GS Large Rate 824	Metel Melting Rate 825	Off-Peak Serv. Rate 826
January	2,098,589	403,641	5,302	2,362	4,379	133,850	4,955	150,591	284,130	27,656	53,355
February	2,109,660	321,778	3,338	453	2,420	97,355	1,785	151,740	310,170	26,269	53,479
March	2,095,348	225,211	3,385	1,650	3,434	171,365	4,916	194,240	338,997	34,552	53,626
April	1,919,683	280,768	3,122	961	3,378	118,846	3,191	205,682	329,855	42,741	50,473
May	2,280,242	413,867	5,013	1,474	1,072	258,221	2,617	223,922	382,537	35,595	63,820
June	2,316,705	528,444	5,434	2,171	-	276,570	-	243,209	317,538	25,457	64,202
July	2,454,603	608,523	5,512	2,066	-	280,727	-	251,832	338,955	32,364	67,505
August	2,627,569	769,589	7,506	1,883	-	314,201	-	302,607	327,104	27,549	69,566
September	2,631,020	791,255	6,138	2,873	-	289,762	-	263,991	340,311	26,560	69,237
October	2,032,702	416,590	3,074	1,954	1,172	115,920	1,501	212,955	275,873	20,361	60,492
November	2,010,085	328,577	3,827	3,092	2,854	205,735	2,961	186,648	319,862	35,010	54,350
December	2,071,087	525,825	8,245	2,547	4,027	150,445	5,365	170,880	247,142	16,507	52,886
12-Month Avg.	2,220,608	467,839	4,991	1,957	1,895	201,083	2,274	213,191	317,706	29,218	59,416
4-Month Avg.	2,507,474	674,453	6,148	2,248	-	290,315	-	265,410	330,977	27,983	67,628
Quarterly Averages											
Jan-Feb-Mar	2,101,199	316,877	4,008	1,488	3,411	134,190	3,885	165,524	311,099	29,492	53,487
Apr-May-Jun	2,172,210	407,693	4,523	1,535	1,483	217,879	1,936	224,271	343,310	34,598	59,499
Jul-Aug-Sep	2,571,064	723,123	6,385	2,274	-	294,897	-	272,810	335,457	28,824	68,769
Oct-Nov-Dec	2,037,958	423,664	5,048	2,531	2,684	157,366	3,276	190,161	280,959	23,959	55,909

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COMPUTATION OF QUARTERLY DEMAND FACTORS

Month	Ind. Pwr Serv. Rate 832	Ind. Pwr Serv. Rate 833	int. Ind. Pwr S. Rate 836	Muni. Power Rate 841	Indust. Off-Peak Rate 845	Firm Contract Rate 847	Rate 844 Railroad	Interdept
January	9,401	196,827	96,000	3,194	375,242	341,676	3,659	2,367
February	11,034	198,330	96,000	1,505	428,126	398,563	4,494	2,823
March	11,725	187,366	100,000	4,250	369,228	386,915	1,438	3,051
April	9,971	172,785	92,000	2,860	336,619	260,896	1,695	3,840
May	10,986	202,611	77,000	2,514	295,880	292,927	720	9,466
June	11,183	219,217	101,000	2,992	285,633	227,765	1,288	4,602
July	20,188	237,644	59,000	2,934	249,772	293,166	784	3,630
August	15,073	243,924	59,000	3,144	251,450	231,456	708	2,808
September	19,297	241,542	59,000	2,656	245,473	268,500	1,136	3,288
October	19,250	227,396	100,000	2,562	291,026	278,405	1,589	2,581
November	17,446	178,026	80,000	2,510	275,098	310,169	1,091	2,830
December	18,875	195,592	74,000	3,185	303,346	287,114	3,675	1,432
12-Month Avg.	14,536	208,438	82,750	2,859	308,908	298,129	1,857	3,560
4-Month Avg.	16,435	235,582	69,500	2,931	258,082	255,222	979	3,582
Quarterly Averages								
Jan-Feb-Mar	10,720	194,174	97,333	2,983	390,865	375,718	3,197	2,747
Apr-May-Jun	10,713	198,204	90,000	2,789	306,044	260,529	1,235	5,969
Jul-Aug-Sep	18,186	241,037	59,000	2,911	248,898	264,374	876	3,242
Oct-Nov-Dec	18,524	200,338	84,667	2,752	289,823	291,896	2,119	2,281

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COMPUTATION OF QUARTERLY DEMAND FACTORS

Month	Total Retail	Rate 811 Base	G.Cents-Res. Rate 812	G.Cents-MFD Rate 813	G.Cents-Comml Rate 820	GS Rate 821	Comml SH Rate 822	GS Rate 823	GS Large Rate 824	Metel Melting Rate 825	Off-Peak Serv. Rate 826
DISTRIBUTION OF COINCIDENT KW JAN-FEB-MAR											
	100.0000%	15.7155%	0.1988%	0.0738%	0.1679%	6.6455%	0.1923%	8.1649%	14.9124%	1.3650%	2.6092%
LOAD @ INPUT TO GENERATION	*2,200,971*	*345,893*	*4,375*	*1,624*	*3,695*	*146,265*	*4,232*	*179,708*	*328,218*	*30,044*	*57,427*
LOSS FACTOR		*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*
SALES @ GENERATION	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
LOAD @ INPUT TO TRANSMISSION	*2,200,971*	*345,893*	*4,375*	*1,624*	*3,695*	*146,265*	*4,232*	*179,708*	*328,218*	*30,044*	*57,427*
LOSS FACTOR		*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*
SALES @ TRANSMISSION	*1,027,146*	*0*	*0*	*0*	*0*	*255*	*0*	*927*	*39,012*	*18,878*	*1,482*
LOAD @ INPUT TO PRIMARY	*1,143,216*	*341,082*	*4,314*	*1,602*	*3,643*	*143,976*	*4,174*	*176,281*	*284,642*	*10,748*	*55,147*
LOSS FACTOR		*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*
SALES @ PRIMARY	*196,284*	*0*	*0*	*0*	*430*	*2,899*	*128*	*13,540*	*125,404*	*10,319*	*12,655*
LOAD @ INPUT TO SECONDARY	*934,760*	*337,451*	*4,268*	*1,585*	*3,174*	*139,544*	*4,001*	*160,865*	*156,207*	*314*	*41,905*
LOSS FACTOR		*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*
SALES @ SECONDARY	*877,769*	*316,877*	*4,008*	*1,488*	*2,980*	*131,037*	*3,757*	*151,057*	*146,683*	*295*	*39,350*
TOTAL AT METER	2,101,199	316,877	4,008	1,488	3,411	134,190	3,885	165,524	311,099	29,492	53,487
DISTRIBUTION OF COINCIDENT KW APR-MAY-JUN											
	100.0000%	19.4320%	0.2156%	0.0732%	0.0702%	10.3697%	0.0921%	10.6319%	15.8155%	1.5390%	2.7894%
LOAD @ INPUT TO GENERATION	*2,290,167*	*445,025*	*4,937*	*1,676*	*1,607*	*237,484*	*2,109*	*243,489*	*362,202*	*35,245*	*63,882*
LOSS FACTOR		*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*
SALES @ GENERATION	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
LOAD @ INPUT TO TRANSMISSION	*2,290,167*	*445,025*	*4,937*	*1,676*	*1,607*	*237,484*	*2,109*	*243,489*	*362,202*	*35,245*	*63,882*
LOSS FACTOR		*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*
SALES @ TRANSMISSION	*865,983*	*0*	*0*	*0*	*0*	*414*	*0*	*1,256*	*43,051*	*22,146*	*1,648*
LOAD @ INPUT TO PRIMARY	*1,392,335*	*438,836*	*4,869*	*1,652*	*1,584*	*233,768*	*2,080*	*238,847*	*314,113*	*12,608*	*61,346*
LOSS FACTOR		*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*
SALES @ PRIMARY	*208,348*	*0*	*0*	*0*	*187*	*4,706*	*64*	*18,345*	*138,388*	*12,106*	*14,077*
LOAD @ INPUT TO SECONDARY	*1,169,163*	*434,163*	*4,817*	*1,635*	*1,380*	*226,573*	*1,994*	*217,958*	*172,381*	*368*	*46,615*
LOSS FACTOR		*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*
SALES @ SECONDARY	*1,097,880*	*407,693*	*4,523*	*1,535*	*1,296*	*212,759*	*1,872*	*204,670*	*161,871*	*346*	*43,773*
TOTAL AT METER	2,172,210	407,693	4,523	1,535	1,483	217,879	1,936	224,271	343,310	34,598	59,499

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COMPUTATION OF QUARTERLY DEMAND FACTORS

Month	Ind. Pwr Serv. Rate 832	Ind. Pwr Serv. Rate 833	int. Ind. Pwr S. Rate 836	Muni. Power Rate 841	Indust. Off-Peak Rate 845	Firm Contract Rate 847	Rate 844 Railroad	Interdept
DISTRIBUTION OF COINCIDENT KW JAN-FEB-MAR								
	0.4939%	8.9466%	4.4847%	0.1475%	18.0092%	17.5945%	0.1489%	0.1295%
LOAD @ INPUT TO GENERATION	10,871	196,913	98,706	3,246	396,378	387,250	3,277	2,850
LOSS FACTOR	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
SALES @ GENERATION	0	0	0	0	0	0	0	0
LOAD @ INPUT TO TRANSMISSION	10,871	196,913	98,706	3,246	396,378	387,250	3,277	2,850
LOSS FACTOR	1.0141	1.0141	1.0141	1.0141	1.0141	1.0141	1.0141	1.0141
SALES @ TRANSMISSION	10,720	194,174	97,333	46	390,865	271,532	0	1,923
LOAD @ INPUT TO PRIMARY	0	0	0	3,155	0	110,333	3,231	887
LOSS FACTOR	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108
SALES @ PRIMARY	0	0	0	97	0	27,615	3,197	0
LOAD @ INPUT TO SECONDARY	0	0	0	3,025	0	81,543	0	878
LOSS FACTOR	1.0649	1.0649	1.0649	1.0649	1.0649	1.0649	1.0649	1.0649
SALES @ SECONDARY	0	0	0	2,841	0	76,571	0	824
TOTAL AT METER	10,720	194,174	97,333	2,983	390,865	375,718	3,197	2,747
DISTRIBUTION OF COINCIDENT KW APR-MAY-JUN								
	0.4744%	8.7766%	3.9853%	0.1325%	13.5519%	11.7252%	0.0553%	0.2704%
LOAD @ INPUT TO GENERATION	10,864	201,000	91,269	3,035	310,360	268,526	1,266	6,192
LOSS FACTOR	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
SALES @ GENERATION	0	0	0	0	0	0	0	0
LOAD @ INPUT TO TRANSMISSION	10,864	201,000	91,269	3,035	310,360	268,526	1,266	6,192
LOSS FACTOR	1.0141	1.0141	1.0141	1.0141	1.0141	1.0141	1.0141	1.0141
SALES @ TRANSMISSION	10,713	198,204	90,000	43	306,044	188,285	0	4,178
LOAD @ INPUT TO PRIMARY	0	0	0	2,950	0	76,507	1,248	1,928
LOSS FACTOR	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108
SALES @ PRIMARY	0	0	0	90	0	19,149	1,235	0
LOAD @ INPUT TO SECONDARY	0	0	0	2,828	0	56,543	0	1,907
LOSS FACTOR	1.0649	1.0649	1.0649	1.0649	1.0649	1.0649	1.0649	1.0649
SALES @ SECONDARY	0	0	0	2,656	0	53,096	0	1,791
TOTAL AT METER	10,713	198,204	90,000	2,789	306,044	260,529	1,235	5,969

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COMPUTATION OF QUARTERLY DEMAND FACTORS

Month	Total Retail	Rate 811 Base	G.Cents-Res. Rate 812	G.Cents-MFD Rate 813	G.Cents-Comml Rate 820	GS Rate 821	Comml SH Rate 822	GS Rate 823	GS Large Rate 824	Metel Melting Rate 825	Off-Peak Serv. Rate 826
DISTRIBUTION OF COINCIDENT KW JUL-AUG-SEP											
	100.0000%	28.9287%	0.2554%	0.0910%	0.0000%	11.7803%	0.0000%	10.8551%	12.9708%	1.0761%	2.7060%
LOAD @ INPUT TO GENERATION	*2,728,562*	*789,338*	*6,970*	*2,482*	*0*	*321,433*	*0*	*296,187*	*353,916*	*29,363*	*73,836*
LOSS FACTOR		*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*
SALES @ GENERATION	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
LOAD @ INPUT TO TRANSMISSION	*2,728,562*	*789,338*	*6,970*	*2,482*	*0*	*321,433*	*0*	*296,187*	*353,916*	*29,363*	*73,836*
LOSS FACTOR		*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*
SALES @ TRANSMISSION	*825,008*	*0*	*0*	*0*	*0*	*560*	*0*	*1,528*	*42,066*	*18,450*	*1,905*
LOAD @ INPUT TO PRIMARY	*1,865,609*	*778,361*	*6,873*	*2,448*	*0*	*316,402*	*0*	*290,541*	*306,928*	*10,504*	*70,904*
LOSS FACTOR		*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*
SALES @ PRIMARY	*210,666*	*0*	*0*	*0*	*0*	*6,370*	*0*	*22,316*	*135,223*	*10,086*	*16,271*
LOAD @ INPUT TO SECONDARY	*1,635,079*	*770,073*	*6,800*	*2,422*	*0*	*306,664*	*0*	*265,131*	*168,437*	*307*	*53,879*
LOSS FACTOR		*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*
SALES @ SECONDARY	*1,535,389*	*723,123*	*6,385*	*2,274*	*0*	*287,967*	*0*	*248,967*	*158,168*	*288*	*50,594*
TOTAL AT METER	2,571,064	723,123	6,385	2,274	0	294,897	0	272,810	335,457	28,824	68,769
DISTRIBUTION OF COINCIDENT KW OCT-NOV-DEC											
	100.0000%	21.5482%	0.2568%	0.1287%	0.1355%	7.9923%	0.1663%	9.6198%	13.8117%	1.1373%	2.7970%
LOAD @ INPUT TO GENERATION	*2,146,154*	*462,458*	*5,511*	*2,763*	*2,908*	*171,527*	*3,568*	*206,456*	*296,419*	*24,407*	*60,029*
LOSS FACTOR		*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*
SALES @ GENERATION	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
LOAD @ INPUT TO TRANSMISSION	*2,146,154*	*462,458*	*5,511*	*2,763*	*2,908*	*171,527*	*3,568*	*206,456*	*296,419*	*24,407*	*60,029*
LOSS FACTOR		*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*
SALES @ TRANSMISSION	*859,425*	*0*	*0*	*0*	*0*	*299*	*0*	*1,065*	*35,232*	*15,336*	*1,549*
LOAD @ INPUT TO PRIMARY	*1,256,882*	*456,027*	*5,434*	*2,724*	*2,867*	*168,842*	*3,519*	*202,520*	*257,065*	*8,731*	*57,645*
LOSS FACTOR		*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*
SALES @ PRIMARY	*177,929*	*0*	*0*	*0*	*339*	*3,399*	*108*	*15,555*	*113,255*	*8,383*	*13,228*
LOAD @ INPUT TO SECONDARY	*1,065,571*	*451,171*	*5,376*	*2,695*	*2,498*	*163,646*	*3,374*	*184,808*	*141,073*	*255*	*43,803*
LOSS FACTOR		*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*
SALES @ SECONDARY	*1,000,604*	*423,664*	*5,048*	*2,531*	*2,346*	*153,668*	*3,168*	*173,541*	*132,472*	*240*	*41,133*
TOTAL AT METER	2,037,958	423,664	5,048	2,531	2,684	157,366	3,276	190,161	280,959	23,959	55,909

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COMPUTATION OF QUARTERLY DEMAND FACTORS

Month	Ind. Pwr Serv. Rate 832	Ind. Pwr Serv. Rate 833	int. Ind. Pwr S. Rate 836	Muni. Power Rate 841	Indust. Off-Peak Rate 845	Firm Contract Rate 847	Rate 844 Railroad	Interdept
DISTRIBUTION OF COINCIDENT KW JUL-AUG-SEP								
	0.6759%	8.9584%	2.1928%	0.1161%	9.2506%	9.9865%	0.0329%	0.1233%
LOAD @ INPUT TO GENERATION	*18,442*	*244,436*	*59,832*	*3,168*	*252,409*	*272,488*	*898*	*3,363*
LOSS FACTOR	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*
SALES @ GENERATION	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
LOAD @ INPUT TO TRANSMISSION	*18,442*	*244,436*	*59,832*	*3,168*	*252,409*	*272,488*	*898*	*3,363*
LOSS FACTOR	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*
SALES @ TRANSMISSION	*18,186*	*241,037*	*59,000*	*45*	*248,898*	*191,063*	*0*	*2,270*
LOAD @ INPUT TO PRIMARY	*0*	*0*	*0*	*3,080*	*0*	*77,636*	*885*	*1,047*
LOSS FACTOR	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*
SALES @ PRIMARY	*0*	*0*	*0*	*94*	*0*	*19,431*	*876*	*0*
LOAD @ INPUT TO SECONDARY	*0*	*0*	*0*	*2,952*	*0*	*57,378*	*0*	*1,036*
LOSS FACTOR	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*
SALES @ SECONDARY	*0*	*0*	*0*	*2,772*	*0*	*53,879*	*0*	*973*
TOTAL AT METER	18,186	241,037	59,000	2,911	248,898	264,374	876	3,242
DISTRIBUTION OF COINCIDENT KW OCT-NOV-DEC								
	0.8753%	9.4664%	4.0007%	0.1396%	13.6948%	14.0183%	0.1012%	0.1103%
LOAD @ INPUT TO GENERATION	*18,785*	*203,163*	*85,861*	*2,995*	*293,911*	*300,855*	*2,172*	*2,366*
LOSS FACTOR	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*	*1.0000*
SALES @ GENERATION	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
LOAD @ INPUT TO TRANSMISSION	*18,785*	*203,163*	*85,861*	*2,995*	*293,911*	*300,855*	*2,172*	*2,366*
LOSS FACTOR	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*	*1.0141*
SALES @ TRANSMISSION	*18,524*	*200,338*	*84,667*	*42*	*289,823*	*210,953*	*0*	*1,597*
LOAD @ INPUT TO PRIMARY	*0*	*0*	*0*	*2,911*	*0*	*85,718*	*2,141*	*737*
LOSS FACTOR	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*	*1.0108*
SALES @ PRIMARY	*0*	*0*	*0*	*89*	*0*	*21,454*	*2,119*	*0*
LOAD @ INPUT TO SECONDARY	*0*	*0*	*0*	*2,791*	*0*	*63,351*	*0*	*729*
LOSS FACTOR	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*	*1.0649*
SALES @ SECONDARY	*0*	*0*	*0*	*2,621*	*0*	*59,488*	*0*	*684*
TOTAL AT METER	18,524	200,338	84,667	2,752	289,823	291,896	2,119	2,281

Cause No. 42658
Petitioner's Exhibit RDG-3
Schedule 4

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COMPUTATION OF QUARTERLY DEMAND FACTORS

Month	Total Retail	Rate 811 Base	G.Cents-Res. Rate 812	G.Cents-MFD Rate 813	G.Cents-Comml Rate 820	GS Rate 821	Comml SH Rate 822	GS Rate 823	GS Large Rate 824	Metel Melting Rate 825	Off-Peak Serv. Rate 826
SUMMARY - COINCIDENT KW AT SOURCE											
Coincident kW at Source											
Jan-Feb-Mar	2,200,971	345,893	4,375	1,624	3,695	146,265	4,232	179,708	328,218	30,044	57,427
Apr-May-Jun	2,290,167	445,025	4,937	1,676	1,607	237,484	2,109	243,489	362,202	35,245	63,882
Jul-Aug-Sep	2,728,562	789,338	6,970	2,482	-	321,433	-	296,187	353,916	29,363	73,836
Oct-Nov-Dec	2,146,154	462,458	5,511	2,763	2,908	171,527	3,568	206,456	296,419	24,407	60,029
Interruptible Credit (Generation)	(57,334)									-15,000	
Coincident kW at Source (Adjusted)											
Jan-Feb-Mar	2,143,638	345,893	4,375	1,624	3,695	146,265	4,232	179,708	328,218	15,044	57,427
Apr-May-Jun	2,232,833	445,025	4,937	1,676	1,607	237,484	2,109	243,489	362,202	20,245	63,882
Jul-Aug-Sep	2,671,229	789,338	6,970	2,482	-	321,433	-	296,187	353,916	14,363	73,836
Oct-Nov-Dec	2,088,820	462,458	5,511	2,763	2,908	171,527	3,568	206,456	296,419	9,407	60,029
Percent of Retail											
Jan-Feb-Mar	100.0000%	16.1358%	0.2041%	0.0758%	0.1724%	6.8232%	0.1974%	8.3833%	15.3113%	0.7018%	2.6790%
Apr-May-Jun	100.0000%	19.9309%	0.2211%	0.0750%	0.0720%	10.6360%	0.0945%	10.9049%	16.2216%	0.9067%	2.8610%
Jul-Aug-Sep	100.0000%	29.5496%	0.2609%	0.0929%	0.0000%	12.0331%	0.0000%	11.0881%	13.2492%	0.5377%	2.7641%
Oct-Nov-Dec	100.0000%	22.1397%	0.2638%	0.1323%	0.1392%	8.2117%	0.1708%	9.8839%	14.1908%	0.4504%	2.8738%
Coincident kW at Transmission											
Jan-Feb-Mar	2,200,971	345,893	4,375	1,624	3,695	146,265	4,232	179,708	328,218	30,044	57,427
Apr-May-Jun	2,290,167	445,025	4,937	1,676	1,607	237,484	2,109	243,489	362,202	35,245	63,882
Jul-Aug-Sep	2,728,562	789,338	6,970	2,482	-	321,433	-	296,187	353,916	29,363	73,836
Oct-Nov-Dec	2,146,154	462,458	5,511	2,763	2,908	171,527	3,568	206,456	296,419	24,407	60,029
Percent of Retail											
Jan-Feb-Mar	100.0000%	15.7155%	0.1988%	0.0738%	0.1679%	6.6455%	0.1923%	8.1649%	14.9124%	1.3650%	2.6092%
Apr-May-Jun	100.0000%	19.4320%	0.2156%	0.0732%	0.0702%	10.3697%	0.0921%	10.6319%	15.8155%	1.5390%	2.7894%
Jul-Aug-Sep	100.0000%	28.9287%	0.2554%	0.0910%	0.0000%	11.7803%	0.0000%	10.8551%	12.9708%	1.0761%	2.7060%
Oct-Nov-Dec	100.0000%	21.5482%	0.2568%	0.1287%	0.1355%	7.9923%	0.1663%	9.6198%	13.8117%	1.1373%	2.7970%

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COMPUTATION OF QUARTERLY DEMAND FACTORS

Month	Ind. Pwr Serv. Rate 832	Ind. Pwr Serv. Rate 833	int. Ind. Pwr S. Rate 836	Muni. Power Rate 841	Indust. Off-Peak Rate 845	Firm Contract Rate 847	Rate 844 Railroad	Interdept
SUMMARY - COINCIDENT KW AT SOURCE								
Coincident kW at Source								
Jan-Feb-Mar	10,871	196,913	98,706	3,246	396,378	387,250	3,277	2,850
Apr-May-Jun	10,864	201,000	91,269	3,035	310,360	268,526	1,266	6,192
Jul-Aug-Sep	18,442	244,436	59,832	3,168	252,409	272,488	898	3,363
Oct-Nov-Dec	18,785	203,163	85,861	2,995	293,911	300,855	2,172	2,366
Interruptible Credit (Generation)			-36,000			-6,334		
Coincident kW at Source (Adjusted)								
Jan-Feb-Mar	10,871	196,913	62,706	3,246	396,378	380,916	3,277	2,850
Apr-May-Jun	10,864	201,000	55,269	3,035	310,360	262,192	1,266	6,192
Jul-Aug-Sep	18,442	244,436	23,832	3,168	252,409	266,154	898	3,363
Oct-Nov-Dec	18,785	203,163	49,861	2,995	293,911	294,521	2,172	2,366
Percent of Retail								
Jan-Feb-Mar	0.5071%	9.1859%	2.9252%	0.1514%	18.4909%	17.7696%	0.1529%	0.1329%
Apr-May-Jun	0.4866%	9.0020%	2.4753%	0.1359%	13.8998%	11.7426%	0.0567%	0.2773%
Jul-Aug-Sep	0.6904%	9.1507%	0.8922%	0.1186%	9.4492%	9.9637%	0.0336%	0.1259%
Oct-Nov-Dec	0.8993%	9.7262%	2.3870%	0.1434%	14.0707%	14.0999%	0.1040%	0.1133%
Coincident kW at Transmission								
Jan-Feb-Mar	10,871	196,913	98,706	3,246	396,378	387,250	3,277	2,850
Apr-May-Jun	10,864	201,000	91,269	3,035	310,360	268,526	1,266	6,192
Jul-Aug-Sep	18,442	244,436	59,832	3,168	252,409	272,488	898	3,363
Oct-Nov-Dec	18,785	203,163	85,861	2,995	293,911	300,855	2,172	2,366
Percent of Retail								
Jan-Feb-Mar	0.4939%	8.9466%	4.4847%	0.1475%	18.0092%	17.5945%	0.1489%	0.1295%
Apr-May-Jun	0.4744%	8.7766%	3.9853%	0.1325%	13.5519%	11.7252%	0.0553%	0.2704%
Jul-Aug-Sep	0.6759%	8.9584%	2.1928%	0.1161%	9.2506%	9.9865%	0.0329%	0.1233%
Oct-Nov-Dec	0.8753%	9.4664%	4.0007%	0.1396%	13.6948%	14.0183%	0.1012%	0.1103%