Liberty Utilities

HSG Group, Inc.

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DE 13-063

Granite State Electric Company d/b/a Liberty Utilities
Notice of Intent to File Rate Schedules

DIRECT TESTIMONY

OF

HOWARD GORMAN

March 29, 2013

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I. QUALIFICATIONS, PURPOSE AND OUTLINE OF TESTIMONY

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

A. My name is Howard Gorman. I am the President of HSG Group, Inc. My business address is 45 Hill Park Avenue, Great Neck, NY 11021.

Q. **On whose behalf are you testifying today?**

A. I am testifying on behalf of Granite State Electric Company d/b/a Liberty Utilities ("Granite State" or the "Company").

Q. **Please describe your educational background and professional experience.**

A. My educational background and professional experience are outlined in my curriculum vitae, which is included as Attachment HSG-1. As shown in that attachment, I have testified in proceedings before the Massachusetts Department of Public Utilities, New Jersey Board of Public Utilities, New York State Public Service Commission, Ontario Energy Board, Pennsylvania Public Utility Commission and Rhode Island Public Utilities Commission.

Q. **What is the purpose of your testimony today?**

A. The purpose of my testimony is to present the following:

1. The Marginal Cost Study ("MCS"), including Granite State's costs and expenses as presented by Company witness Ms. Mason and Dr. Schmidt;
2. Proposed revenue allocation of the total Rate Year distribution revenue requirement among the Company's service classifications under the Company's tariff's for electric service, N.H.P.U.C. No. 18 ("Tariff"); and

3. The Company's proposed rate design for each service classification under the Tariff, including a) the rates to produce an increase in revenue of $14,168,940 based on the Company's revenue requirement in the adjusted Test Year, and b) the rates to produce an additional increase in revenue of $1,250,467 based on the Step Increase, described by Ms. Mason and Dr. Schmidt

Q. Are you sponsoring any schedules?

A. Yes. I am sponsoring the following Schedules, which were prepared by me:

Attachment HSG-1- Resume

- Resume of Howard S. Gorman

Attachment HSG-2- Marginal Cost Study

- Attachment HSG- 2 Index lists each of the schedules in Attachment HSG-2
- Schedules HSG-1 to HSG-18 present the MCS

Attachment HSG-3

- Attachment HSG- 3 Index lists each of the schedules in the Attachment HSG-3
- Schedules HSG-18 to HSG-19 present the proposed revenue allocation
- Schedules HSG-20 to HSG-21I present the proposed new rate design and distribution rates for each service classification

Attachment HSG-4

- Attachment HSG- 4 Index lists each of the schedules in the Attachment HSG-4
- Schedules HSG-22 to HSG-23I present the present the proposed distribution rates including the Step Increase for each service classification

Q. **What rate classes are included in the Company's MCS?**

A. The following rate classes are included in the MCS:

- Domestic Service (Rate D)
- Domestic-Optional Peak Load Pricing (Rate D-10)
- General Service Time-of-Use (Rate G-1)
- General Long-Hour Service (Rate G-2)
- General Service (Rate G-3)
- Outdoor Lighting Service (Rate M)
- Limited Total Electric Living (Rate T)
- Limited Commercial Space Heating (Rate V)

II. MARGINAL COST OF SERVICE STUDY

Q. Please provide an overview of the Marginal Cost of Service Study.

A. The purpose of the MCS is to compute the incremental, or marginal, cost to the utility to provide the next unit of service, *i.e.*, the next kW of demand served or the next customer connected to the system. In this section of my testimony, I explain the methodology used in the MCS, identify and describe the supporting schedules and present the results.

Q. **Did you calculate a marginal revenue requirement?**

A. Yes, the total marginal revenue requirement for each rate class is shown on Schedule HSG-1. The marginal revenue requirement (column G) is the sum of:

- Marginal Demand-related revenue requirement (column C), which equals marginal Demand cost per kW (column A) times demand served (column B), and

- Marginal Customer-related revenue requirement (column F), which equals marginal Customer cost (column D) times number of customers (Column E).

Q. **What are the components of marginal costs in the MCS?**

A. The MCS estimates the cost of providing an additional unit of service. In this case, service includes two components:

- Marginal Demand-related costs: The costs associated with an increase in the peak demand the Company needs to meet; and
- Marginal Customer-related costs: The costs associated with attaching an additional customer to the system to deliver electricity as well as to meter, bill and collect from that customer.

Q. **What costs are included in marginal Demand-related costs?**

A. Marginal Demand-related costs are the costs associated with meeting an additional unit of peak demand, and comprise the cost of distribution plant, including substations, the primary and secondary distribution system, and transformers, including for each asset the initial capital cost and ongoing annual costs. Marginal Demand costs are expressed in levelized annual dollars per kW of peak demand, as I discuss below.

The Marginal Demand costs for each rate class are presented on Schedule HSG-2. The capital costs per unit of marginal demand are shown for Primary/ Secondary Distribution assets (column A) and Transformers (column B). These costs are multiplied by the long-term carrying charge rate (“LCCR”) for each asset type (columns C and D, respectively), to determine the Annual and

Monthly Marginal Costs per kW Demand (columns E and F, respectively), which are carried forward to Schedule HSG-1.

Q. **What does the Long-Term Carrying Charge Rate (“LCCR”) represent?**

A. The LCCR is the constant (or level) rate, stated as a percent of initial capital cost, that provides for the following costs and other items to be recovered by the utility:

- Initial capital cost, recovered through depreciation expense;
- After-tax return on initial capital cost;
- Ongoing costs for operations and maintenance (“O&M”), including an adder for Administrative & General (“A&G”) costs;
- Ongoing costs for property taxes (if applicable) and insurance; and
- After-tax return on working capital related to the O&M costs.

The calculations of the LCCRs for each asset type are shown on the following schedules:

- Schedule HSG-12 LCCR - Distribution Plant
- Schedule HSG-13 LCCR - Line Transformers
- Schedule HSG-14 LCCR - Services
- Schedule HSG-15 LCCR - Meters
- Schedule HSG-16 LCCR - Street Lights

The resulting LCCR for each asset type is summarized by component on Schedule HSG-8A, and carried forward to Schedule HSG-8. The LCCRs for Primary / Secondary Distribution and Transformers are carried forward to Schedule HSG-2, columns C and D, respectively. The

LCCRs for Services and Meters are carried forward to Schedule HSG-4, columns B and E, respectively. The LCCR for Street Lights is carried forward to Schedule HSG-4, column B, line 7.

Q. What are the inputs to the LCCR calculations?

A. The inputs for the LCCR calculations are shown on Schedule HSG-8.

Tax depreciation life and method, and regulatory depreciation life, were provided by the Company (lines 1-15).

O&M expense for each asset type, stated as a percent of asset cost in current dollars, were computed on Schedule HSG-9. On this schedule, each item of Distribution plant O&M expense was assigned to one of the asset types: Primary / Secondary, Line Transformers, Services, Meters, Street Lights. Costs identified as Other were allocated among these assets. The O&M costs for each asset type were divided by the current cost of the assets, to determine a percentage of O&M Rates as % of Current Plant Cost (line 30). An A&G adder (line 31) was added to these percentages, and the totals (line 32) were carried forward to Schedule HSG-8, lines 21-25, to use in computing LCCRs.

Other Plant Costs for each asset type, stated as a percent of asset cost in current dollars, were computed on Schedule HSG-10. These percentages (line 8) were carried forward to Schedule HSG-8, lines 21-25, to use in computing LCCRs.

Long-term inflation is based on U.S. Macro Baseline Forecast Summary, Moody's Analytics, April 2012. Weighted average cost of capital, return on equity and income tax rates are the same as used in computing the Revenue Requirement as presented in Ms. Mason and Dr. Schmidt's direct testimony in support of permanent rates.

Q. **How was the A&G adder calculated?**

A. The A&G adder expresses the relationship between A&G costs on the one hand, and Distribution O&M and Customer records costs, on the other. The A&G adder used in the MCS is calculated on Schedule HSG-11, based on 2012 costs.

The ratio of A&G costs to Distribution O&M and Customer records costs for 2012 was compared to the ratios for recent historical periods. Historical annual A&G costs, detailed by FERC account (lines 1-13) were divided by the sum of Distribution O&M costs (from FERC Form 1) and Customer costs (also from FERC Form 1), to determine the annual ratio of A&G costs to operating costs. Annual ratios (line 20) and ratios for longer periods (lines 22-25) were computed. The ratio has been fairly stable over time; the most recent year was used in the MCS so as to match the period for Distribution O&M Costs and Customer costs. The A&G adder (line 25) was applied to Distribution O&M costs (Schedule HSG-9) and Customer costs (Schedule HSG-6A).

Q. **What costs are included in marginal Customer-related costs?**

A. Marginal Customer-related costs are the costs associated with connecting an additional customer, and comprise the cost of a service drop and a meter, ongoing operating costs for those assets, and ongoing metering, billing and collections costs. Marginal Customer-related costs are in levelized annual dollars per customer, as I discuss below.

The Marginal Customer- related costs for each rate class are presented on Schedule HSG-4. The capital costs per customer are shown for Services (column A) and Meters (column D). These are multiplied by the LCCR for each asset type (columns B and E, respectively) to determine the Annual Marginal Costs per Customer related to Capital (columns C and F, respectively); LCCR includes operating costs of the assets. Ongoing metering, billing, and collections costs are shown in column G. Total Annual Marginal cost per customer, which are carried forward to Schedule HSG-1, is equal to the sum of columns C, F and G, I, is shown in column H; monthly costs are in column I.

Q. **Please describe how the marginal capital cost of distribution plant was calculated.**

A. The marginal capital cost of distribution plant was calculated by comparing distribution plant additions related to growth over the period since the Company's last base rate case, to the peak demands over that period, and performing a regression analysis.

The first step was to determine distribution plant additions for the period (Schedule HSG-3B). Distribution plant added each year, detailed by FERC account, was obtained from the Company's FERC Form 1 (lines 1-9) and summarized as to Primary voltage, Secondary voltage or Transformer (lines 11-14). The annual cost of new additions was restated in current year (2012) dollars (lines 17-20).

Total plant additions were multiplied by the portion of distribution plant additions related to load growth; that is, to serving additional load (line 22), to compute the annual current dollar cost of additions due to growth (lines 24-27). The cumulative annual current dollar cost of additions due to growth (lines 29-32) is the cumulative investment in distribution plant required to meet incremental load, or the capital cost of marginal demand.

Q. **How did you allocate distribution plant assets between the primary voltage system and the secondary voltage system?**

A. The Company's primary distribution system operates at voltages 2.4kV and greater; the secondary system operates at voltages under 2.4kV. The Company provided conductor miles and circuit miles of its overhead and underground systems, detailed by voltage. This information was used to allocate the costs between primary and secondary voltages (Schedule HSG-3C). The primary percentages are carried forward to Schedule HSG-3B.

Q. **What values did you use to restate from historical to current year (2012) dollars?**

A. Capital additions were restated using the Handy-Whitman Construction Costs Index. Annual costs were restated using Bureau of Labor Statistics GDP cost deflators. These values are shown on Schedule HSG-17.

Q. **How did you determine the portion of capital additions related to load growth, as shown on Schedule HSG-3B, line 24?**

A. The Company provided the annual capital additions related to growth for 1997-2012 (Schedule HSG-3D, lines 1-7). The amount for each year was divided by total distribution plant capital additions. The results represent the annual portion of distribution plant additions related to growth (line 11, carried forward to Schedule HSG-3B, line 24).

Q. **After you determined the distribution plant additions related to growth, how did you compute the marginal capital cost of distribution plant?**

A. The cumulative cost of distribution plant additions related to growth, detailed as to primary, secondary and transformers, was carried forward from Schedule HSG-3B to Schedule HSG-3A. Then a regression analysis was performed (Schedule HSG-3A), with system peak demand as the independent variable and cumulative additions for primary, secondary and transformers as the dependent variables. Statistically correlations were found (lines 20-21), therefore the slopes of the lines (i.e., the coefficients) were deemed to be the marginal capital cost per kW for primary, secondary and transformers (line 19).

The results are summarized on Schedule HSG-3, where they are also adjusted to reflect that approximately 33.4% of the G-1 rate class demands are served at primary voltages (i.e., approximately 66.6% are served at secondary voltages); and that approximately 0.1% of G-2 rate class demands are served at primary voltages. These capital costs for each asset type are carried forward to Schedule HSG-2.

Q. **Please describe how the marginal capital costs of services and meters were calculated.**

A. Capital costs for Services and for Meters for each rate class were obtained using proxy data from other utilities in the Northeast. Proxy data were used because they could be obtained at a significant savings in time and cost to Granite State. In my opinion, it is reasonable to use proxy data for Services and Meters because the relative costs (for the different rate classes) are similar among electric utilities. The capital costs per customer are shown on Schedule HSG-5, and are carried forward to Schedule HSG-4.

Q. **Please describe how the marginal capital costs of Street Lights were calculated.**

A. The marginal capital costs for Street Lights were computed by obtaining historical annual plant additions from the Company's FERC Form 1 (Schedule HSG-3E, line 1), removing retired assets, then restating the costs in current year (2012) dollars (line 10). The total cost per customer was divided by number of customers (line 13) and carried forward to Schedule HSG-4, line 7.

Q. **Please describe how ongoing metering, billing and collections costs were calculated.**

A. The first step was to obtain historical costs, detailed by FERC account (Schedule HSG-6B, lines 1-10). The annual costs were carried forward to Schedule HSG-6A, where they were restated in current year (2012) and computed on a per-customer basis.

The correlation between number of customers and costs was weak (line 23), therefore the cost per customer for 2012 was used (line 19). The A&G adder (line 20, from Schedule HSG-9) was added to these costs, and the total (line 21) was carried forward to Schedule HSG-6. The most recent year was used in the MCS so as to match the period for Distribution O&M Costs and Customer costs.

On Schedule HSG-6, the costs per customer metering, billing and collections costs were weighted to reflect the comparative effort for each rate class, and the results were carried forward to Schedule HSG-4, column G.

Q. How was the total marginal cost for each rate class calculated?

A. The Marginal Demand cost per kW for each rate class is presented on Schedule HSG-1, column A (carried forward from Schedule HSG-2). These costs are multiplied by the class Non-Coincident Peak ("NCP") demands (column B) to produce Annual Marginal Demand Cost for each rate class (column C).

NCP demands reflect the diversity of demand on the system; that is, rate classes peak at different times (for Granite State, in different seasons) and the system is designed to meet demand at all times. The NCPs were developed based on the average of the load factors for each rate class for each of the years 2008 through 2012; the average load factors were applied to normalized kWh deliveries for the Rate Year, as presented at Schedule HSG-7. The use of a multi-year average load factor provides a representative picture of demands likely to be experienced in a year because it averages out the effect of historical weather and applies the resulting load factors to weather-normalized kWh sales.

The Marginal Customer-related cost per customer for each rate class is presented on Schedule HSG-1, column D (carried forward from Schedule HSG-4). These costs are multiplied by number of customers (column E) to produce Annual Marginal Customer Cost for each rate class (column F).

The total marginal cost of each rate class is the sum of Marginal Demand (column C) and Marginal Customer (column F), and is shown in column G.

Q. **Were the results of the MCS used to design delivery rates?**

A. Yes, the results of the MCS, presented on Schedule HSG-1, were the basis for revenue allocation, which I discuss next, and rate design, which I discuss later in this testimony.

III. DEVELOPMENT OF RATE CLASS REVENUE ALLOCATIONS

Q. What is the purpose of revenue allocation?

A. The purpose of revenue allocation is to allocate the overall revenue requirement among the various rate classes.

Q. **What were the guiding principles that you used for revenue allocation?**

A. There were two guiding principles used in the revenue allocation process. The first principle was to reflect the results of the MCS as closely as possible. The second principle was to mitigate extreme rate impacts both on rate classes and on individual customer subgroups, a concept known as gradualism. These concepts are put forth in the book *Principles of Public Utility Rates*, Bonbright et al., 1988 edition which is often cited and relied on for guidance with regard to revenue and rate design for regulated utilities.

Q. **Did you prepare a schedule to present the Company's proposed revenue allocation?**

A. Yes, Schedule HSG-18 presents the revenue allocation computations, and the proposed revenue allocation is on line 20.

Q. **Please describe how you determined the proposed revenue allocation.**

A. The first step in revenue allocation was to summarize the marginal costs by rate class, as determined in the MCS (Schedule HSG-18, lines 1-3, carried forward from Schedule HSG-1).

The total of the marginal costs (line 3) is less than the proposed distribution revenue requirement excluding other revenue (lines 5-7), therefore all rate classes were increased proportionately (line 9) and the resulting preliminary revenue allocation was computed (line 10). This approach is sometimes referred to as the equi-proportional allocation method. It is necessary because the total marginal costs are less than the total revenue requirement, therefore designing rates based solely on marginal costs would not recover all of the utility’s costs.

The preliminary revenue allocation was compared to distribution Rate Year revenue at current rates (line 12, carried forward from Schedule HSG-19) to determine the preliminary increases in dollars (line 13), percent (line 14) and relative to the average increase of 56.40% (line 15).

The preliminary revenue allocation was adjusted to reflect two constraints:

- No rate class receives a decrease (line 19); this constraint was moot because no rate class received a decrease under the preliminary revenue allocation.
- No rate class receives an increase greater than 150% of the average (line 20); that is, the overall distribution revenue increase is 57.45% (Schedule HSG-18, line 14), therefore no class will have an increase greater than 86.17%.
- Lighting (Rate M) was given the system average increase.

These two constraints resulted in a shortfall of approximately $747,000 compared to the revenue requirement. The shortfall was recovered from classes receiving a small than average increase.

The proposed revenue for each rate class is shown on line 22, the increases are on line 23, the percentage increases (based on normalized distribution revenue at current rates) are on line 24 and the relative increases are on line 25. Line 27 compares the proposed revenue for each rate class to the proportionally adjusted marginal cost.

Q. **How did you compute the normalized revenue at current rates shown on Schedule HSG-18, line 10?**

A. The normalized revenue at current rates is computed on Schedule HSG-19. It was computed by applying current tariff rates to the forecast number of customer bills and delivery kWh.

For rate classes Domestic (D), Domestic- Optional Peak Load (D10) and General Time-of-Use (G-1), the splits of kWh among different rate blocks and on-peak / off-peak were assumed to be the same proportion of total rate class as in the Rate Year. For General Time-of-Use (G-1) and General Long-Hour (G-2), Billing Demand units were assumed to change proportionally to rate class kWh.

Q. **How did you determine to limit the increase for any rate class to 150% of the average?**

A. A movement towards costs is essential to reduce existing interclass subsidies and improve efficient pricing for all rate classes. However, the maximum increase assigned to any rate class is often constrained in the revenue allocation process to mitigate extreme rate impacts. In this case, a maximum of 150% of the average was chosen in order to have the classes where increases are constrained (Domestic- Optional Peak Load (D10), General Time-of-Use (G-1) and Limited Total Electric Living (T)), move towards costs and pay a proportionate amount of their adjusted marginal costs, with the goal of reducing interclass subsidies. Without this limitation, these classes would experience increases of 93%-107%, equal to 1.63 times the average increase to 1.87 times the average increase.

IV. DEVELOPMENT OF RATES

Q. What is the purpose of rate design?

A. The purpose of rate design is to determine the monthly, volumetric, demand-based and other rates for each rate class that produce target revenue determined in the revenue allocation process.

Q. **What were the guiding principles that you used in developing the rate design?**

A. The guiding principles used in developing the rates are:

- To produce the target revenue for each rate class determined in the revenue allocation process;
- To reflect marginal costs as appropriate;
- To mitigate extreme rate impacts on customer subgroups;
- To help meet other goals of the utility and the regulator such as promoting efficient use of resources, conservation or local generation;
- To produce rates for customers and revenues for the utility that are reasonably stable and predictable while reflecting the nature of the costs they are designed to recover, (e.g., recovering customer-related costs in the monthly customer charge); and
- To produce typical bills for each rate class that are similar to those of New Hampshire customers served by other utilities in the state.

Q. **Did you prepare schedules to present the proposed rates and to compare the revenue at current rates to the proposed rates?**

A. Yes. A summary of the proposed rate design is present on Schedule HSG-20. For each rate class, current rate revenue is in column A, target revenue is in column B and the percentage increase is in column C.

Schedule HSG-21 compares the current rates to the proposed rates, and shows the overall percentage increase (column A), as well as the current and proposed customer charges and the increases in customer charges (columns B-D), the current and proposed demand rates and the increases in demand rates (columns E- G) and the current and proposed kWh-based rates and the increases in kWh-based rates (columns H-J).

The demand rates on the schedule include the basic distribution rates, as well as discounts for High Voltage Metering, High Voltage Delivery and Interruptible Credits, and also reflect Optional Demand charges. The kWh-based rates shown on the schedule include the basic distribution rates, as well as the charges and credits for Renewable Energy, Default Service Reclass, Storm Fund Adjustments and Rate Case surcharge.

Schedule HSG-21 also shows the proportion of distribution revenue for each rate class to be received from customer charges, demand charges and kWh-based rates under current rates (columns K-M) and proposed rates (column N-P).

Q. Do the proposed rates produce the target revenue for each rate class?

A. Yes. The amounts in Schedule HSG-20, column Z, representing the differences between the proposed rates and the target revenue (to the nearest thousand), are very small.

Q. **How did you compute the rates for Domestic Service (Rate D) and Domestic Off-Peak (Rate D-6)?**

A. First, the current customer charge for D and D-6 was increased to $11.00 per month. This rate is well below the marginal customer cost, and is typical for residential customers in New Hampshire. After this rate was established, the various kWh-based rates were computed, by increasing each of the current rates, applicable to different blocks and different types of service within these classes, to produce the target revenue for the class.

Rate D includes a blocked kWh rate; under current rates the tail block rate is 160% greater than the head block rate. The goal of inclining block rates is to promote conservation, however an incline of 160% is very unusual and does not reflect how distribution costs are incurred. Therefore, an incline of 50% was used (i.e., tail block rate is 50% greater than head block rate). This is still a steep incline, in order to promote conservation, while more closely reflecting costs and also moving closer to rate designs of other New Hampshire utilities.

Q. **How did you compute the rates for Domestic Optional Peak Load Pricing (Rate D-10)?**

A. First, the current customer charge for D-10 was increased to $11.00 per month, the same as for Rate D. This rate is substantially below the marginal customer cost. After this rate was established, the kWh-based rate was computed, to produce the target revenue for the class.

Q. **How did you compute the rates for General Service Time-of-Use (Rate G-1)?**

A. This rate class includes the Company's largest customers, with minimum demand of 180 kW; the average monthly usage is approximately 247,500 kWh per customer. The current customer charge for G-1 was increased from $93.37 to $300.00 per month. Although this is greater than the marginal customer cost, and is a large percentage increase, it was necessary to mitigate the increases to the demand charge and the kWh-based charge. In my experience, large customers such as those in G-1 prefer the certainty of the fixed customer charge to higher demand and kWh-based charges. The proposed customer charge is comparable to that of other New Hampshire utilities.

After the customer charge was established, the demand charge was increased by 75% to $7.12 per kW, which is well below the marginal demand cost, and is comparable to demand charges for large industrial customers of other New Hampshire utilities. The last step was to increase the kWh-based charges in order to produce the target revenue for the class; the off-peak rate equals the business profits tax included in base rates and the on-peak rate is the rate needed to produce the target revenue.

The proposed G1 rate structure is similar to that offered by other New Hampshire utilities to their large customers, and the total bill for typical G1 customers will be lower than for similar customers served by other New Hampshire utilities.

Q. **How did you compute the rates for General Long Hour Service (Rate G-2)?**

A. This rate class includes customers with minimum demand of 20 kW and up to 200 kW; the average monthly usage is approximately 14,800 kWh per customer. The current customer charge for G-2 was increased from $24.98 to $50.00 per month. Although this is greater than the marginal customer cost, and is a large increase, it was necessary to mitigate the increases to the demand charge and the kWh-based charge.

After the customer charge was established, the demand charge was increased to $7.18 per kW, which is well below the marginal demand cost, and is comparable to demand charges for similar customers of other New Hampshire utilities. The last step was to increase the kWh-based charges in order to produce the target revenue for the class.

The total bill for typical G2 customers will be lower than for similar customers served by other New Hampshire utilities.

Q. **How did you compute the rates for General Service (Rate G-3)?**

A. This rate class includes smaller commercial and industrial customers; the average monthly usage is approximately 1,400 kWh per customer. The current customer charge for G-3 was increased to $11.00 per month. This rate is well below the marginal customer cost. After this rate was established, the kWh-based rate was computed, to produce the target revenue for the class.

Q. **How did you compute the rates for Limited Total Electric Living (Rate T)?**

A. First, the current customer charge was increased to $11.00 per month. This rate is well below the marginal customer cost. After this rate was established, the kWh-based rate was computed to produce the target revenue for the class.

Q. **How did you compute the rates for Limited Commercial Space Heating (Rate V)?**

A. This class has only a kWh-based charge and a minimum charge. The kWh-based charge was computed to produce the target revenue for the class. The minimum charge was increased by the increase in revenue for the class.

Q. **How did you compute the rates for Outdoor Lighting Service (Rate M)?**

A. The annual fixture charges were increased by approximately 58.7%, representing the system average increase to produce the target revenue for the class.

<u>Customer Impacts</u>

Q. Did you compute the impacts of the proposed rates on typical customers?

A. Yes. Schedules HSG-21A through Schedules HSG-21I present the impacts of the proposed rates on a range of customer profiles in each class. The schedules compute the change in monthly costs, as well as the percent change in delivery cost and the percent change in total bill.

<u>Step Increase Rates</u>

Q. How were the proposed rates included the Company's Step Increase determined?

A. The Step Increase is proposed to be recovered on a kWh-delivered basis. The total increase in revenue from the Step Increase was allocated among the rate classes based on kWh-delivered. For most classes, each kWh-based charge was increased by thre same amount, $0.00135 cents per kWh. For Rate G1, the tail block rate was not changed, therefore the head block was increased by the amount needed to produce the additional revenue for the class.

The proposed Step Increase rates are presented on Schedule HSG-22. In addition, Schedules

HSG-23A through Schedules HSG-23I present the impacts of the proposed rates including the Step Increase on a range of customer profiles in each class.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes it does.