A METHOD TO ASSESS THE ECONOMIC FEASIBILITY OF TIME-OF-DAY PRICING FOR RESIDENTIAL CUSTOMERS

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The NRRI is making this report available to those concerned with state utility regulatory issues since the subject matter presented here is believed to be of timely interest to regulatory agencies and to others concerned with utilities regulation.

The NRRI appreciates the cooperation of the New York State Department of Public Service with the contractor in preparing this study and for their permission to make this information available to others interested in regulatory affairs.

SUMMARY

This study develops a method that can be used to determine the economic feasibility of New York electric utilities adopting time-of-day pricing in the sale of electricity to residential customers. While there are alternative methodologies for evaluating the economic feasibility of time-of-day pricing, the method presented in this report was chosen because it is simple and can be employed even though certain data are not available. The analysis is accomplished by investigating a number of factors that must be considered together. The factors include the marginal cost of generation and transmission-distribution facilities that might be saved if time-of-day pricing were adopted; the incremental cost of purchase, installation, and operation of metering equipment to record residential use during more than one daily time period; the probable residential customer response to higher prices for electricity during peak consumption periods; and the distribution of residential customers by quantity of electricity used during peak periods.

Data were collected on these factors for two example test cases--one for an upstate New York composite utility and the other for a downstate New York composite utility. The data for the composite utilities represent simple averages of the respective figures for a sample of New York utilities. These two example cases of the method are used to best enable the reader to understand the method and also provide a test for its applicability. <u>Because the data used were for purposes of illustrating our method of assessing the economic feasiblity of time-of-day pricing and not for actually testing whether or not time-of-day pricing is cost-effective, the reader is cautioned not to take the test results as definitive. This report is not intended to offer a solution as to whether time-of-day pricing is cost-effective in New York State; it is a description of a method for determining the economic feasibility of time-of-day pricing in the state.</u>

It was necessary to make several simplifying assumptions to estimate many of the parameters used to test the method. Because of this, it would be a misuse of this report if someone were to employ any of the numbers contained herein without first becoming familiar with the assumptions that are presented in the body of this report.

For most utilities, reasonably good information was available for estimating the incremental cost of generation and transmission-distribution capacity. The cost of new metering equipment was obtained from manufacturers and checked with utilities that are experimenting with such equipment. We did not obtain what can be considered reliable information on residential customer response to time-of-day pricing and therefore we have substituted assumptions for these data. Most utilities supplied reasonably satisfactory data on residential customer usage.

We believe that our method for analyzing the economic feasibility of time-of-day pricing will give valid results when satisfactory data, particularly concerning customer response, become available. At the end of section 1 a theoretically more complete methodology is described that can be used when reliable customer response data become available.

Briefly, our method is to develop an annual saving per kilowatt for new generation and transmission-distribution capacity and attendant O&M expenses and compare this with the per-customer annualized incremental cost of purchasing, installing, and operating the needed metering equipment. From this it can be determined what fraction of a kilowatt of per-customer demand must be saved by time-of-day pricing during the peak period just to pay for the new measuring equipment. This is the "break-even" point. The kW "break-even" point is translated into a kWh "break-even" point by use of a load factor; the kWh figure is then compared to average peak-period consumption during peak months to derive the percent of peak-period consumption that the required kWh reduction represents. This comparison is made for different consumption-size customers. The method then assumes two scenarios (where peak and off-peak prices are equal)--one in which the peak-period price of electricity is increased 10 percent and another in which peak-period price is increased 50 percent over the current price. Dividing the percentage of kWh reduction by the assumed price changes determines what degree of price elasticity would be necessary for each size class if the saving in capacity costs were to equal the costs of metering. Where these elasticities are considered attainable or reasonable (based on available data), a tentative decision can be made that time-of-day pricing is feasible for a customer of given size. This method was applied to several metering technologies, each with different costs. The results of the test cases follow.

The annualized benfits per kW saved by introducing time-of-day pricing would be $61 for the upstate composite utility and $96 for the downstate composite utility. These figures are in 1978 dollars. To derive the annualized per-kW benefits it was necessary to make several assumptions: the per-kW marginal cost is unaffected by the implementation of time-of-day pricing; the off-peak period has no capacity responsibility; capacity figures are for the secondary voltage level and include losses; and 100 percent of the energy consumption reduced in the peak period is shifted to the off-peak period. A peak-period hour is defined as an hour when demand is at or near the system peak.

On the basis of the assumptions described in section 3, the annualized incremental cost of introducing time-of-day pricing ranges from $9 to $56 per customer for the upstate composite utility and from $9 to $57 for the downstate composite utility (depending on the type of metering system employed). This is a broad range of costs. The annualized incremental costs of the two-dial kWh, three-dial kWh, and the two-dial kWh with peak-demand meters are clustered at the top of the range cost (from $34 to $57). The automatic meter reading systems are somewhat less costly. The annualized incremental cost of the American Science and Engineering automatic metering system was estimated to be $22. For the International Teledata system, the annualized incremental cost was estimated to be $9 (with an assumed cost for telephone line leasing).

The International Teledata figure is considerably lower than the others. While we are confident that the data used to derive the figure were supplied in good faith, we believe that the number is too tentative to allow drawing any conclusions. In addition, the uncertainty of telephone line lease costs puts the International Teledata figure further in doubt. Before using any of these numbers or drawing any conclusions from them, the reader is urged to become familiar with the assumptions presented in section 3 of this report.

Depending on the type of metering system implemented in the test cases, a comparison of benefits and costs showed that between 0.15 and 0.92 kW per customer must be saved during the peak period to justify time-of-day pricing for the composite upstate utility, and 0.09 to 0.59 kW per customer for the composite downstate utility.

On the basis of previous time-of-day pricing experiments, we have assumed that the long-run peak-period own-price elasticity (customer response) to time-of-day pricing in New York State must be less than or equal to -0.9 in absolute value if it is to be considered reasonable. This figure represents the midpoint of the peak-period own-price elasticity range of -0.6 to -1.3. The use of the -0.9 elasticity in this method depends on the following assumptions: the elasticities are constant and invariant with customer size; the cross-price elasticity for the effect of the off-peak electricity price on the on-peak period consumption is zero; the elasticity represents customer response to the introduction of time-of-day pricing when existing electricity prices are the same for low and high consumption periods; and the load characteristics of New York utility systems are not significantly different from the load characteristics of the systems used to derive the elasticity estimates.

Test case results are summarized in tables 1 and 2. These tables show the kWh cutoff points and percent of residential customers cost-effectively metered for each of the four meter types. The results, of course, depend on the assumptions made.

The analysis described here is based on the assumed elasticities. It is our opinion that dependable elasticities suitable for rate design purposes must be determined for each individual utility using the best available data applicable to that utility. No utility or commission should expect that customer response to price changes on any one system will be exactly the same as on another system or the same as the average response on a group of systems. In addition, greater price changes than assumed in the test cases would usually result when a utility moves from a situation where price is the same for high and low consumption periods to one of time-of-day pricing. This is because the implementation of time-of-day pricing would be associated with prices based on marginal costs instead of on average costs.

Table 1. UPSTATE UTILITIES: REQUIRED kWh CONSUMPTION AND PERCENT OF CUSTOMERS COST-EFFECTIVELY METERED FOR THE RESIDENTIAL CUSTOMER CLASS, ASSUMING A PEAK-PERIOD OWN-PRICE ELASTICITY OF -0.9

	kWh Consumption Size Given Price Increases of			
	10 Percent		50 Percent	
	kWh Size	Percent Customers	kWh Size	Percent Customers
1. Two-dial kWh meter	3,677[a]	--	801	16.1
2. Three-dial kWh meter	4,202[a]	--	801	16.1
3. Two-dial peak demand	6,040[a]	--	1,001	9.3
4. Automatic meter-reading (International Teledata)	1,001	9.3	251	69.8
5. Automatic meter-reading (American Science and Engineering)	2,001	1.4	501	37.9

a Actual kWh consumption size breakpoint; less than 1.4 percent of customers could be cost-effectively metered.

NOTE: Data taken from tables 13 through 17.

Table 2. DOWNSTATE UTILITIES: REQUIRED kWh CONSUMPTION AND PERCENT OF CUSTOMERS COST-EFFECTIVELY METERED FOR THE RESIDENTIAL CUSTOMER CLASS, ASSUMING A PEAK-PERIOD OWN-PRICE ELASTICITY OF -0.9

	kWh Consumption Size Given Price Increases of			
	10 Percent		50 Percent	
	kWh Size	Percent Customers	kWh Size	Percent Customers
1. Two-dial kWh meter	2,465[a]	--	511	46.8
2. Three-dial kWh meter	2,788[a]	--	751	24.7
3. Two-dial peak-demand	4,020[a]	--	1,001	13.3
4. Automatic meter-reading (International Teledata)	751	24.7	241	80.9
5. Automatic meter-reading (American Science and Engineering)	2,001	2.5	241	80.9

a Actual kWh consumption size breakpoint; less than 0.8 percent of customers could be cost-effectively metered.

NOTE: Data taken from tables 18 through 22.

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TABLES

Section 1
INTRODUCTION

PURPOSE OF THE STUDY

The scope of this study was to develop and present a method of assessing the economic feasibility of implementing time-of-day pricing of electricity for residential customers in New York State. No attempt was made to determine if time-of-day pricing is in fact economically feasible. The numbers presented in this report are strictly for purposes of demonstrating the method and are not intended as evidence of the cost-effectiveness of time-of-day pricing.

A study such as this is important because time-of-day pricing is one of several load management alternatives that can be employed to moderate the increasing demand for electric power. Through load management techniques a utility may be able to lower its system peak and thereby improve its system load factor. This is accomplished by not only lowering the peak demand on the system but also by shifting electricity consumption from the peak period to the off-peak period. This can result when a multi-period pricing structure is adopted that discriminates between high- and low-cost periods. In addition, time-of-day pricing can be employed as a tool to alter the allocation of resources by pricing electricity to reflect the opportunity cost of the resources employed to produce it. A higher price per kW or per kWh is justified during peak periods to cover the the higher costs associated with supplying power during this period.

This analysis is not concerned with deriving electricity rates based on marginal cost. The concern is how to determine if the cost of measuring customer kW or kWh consumption under time-of-day pricing is justified on the basis of assumed customer response to time-of-day rates and the resulting saving in capacity costs and energy costs.

Before describing the method, some discussion of the reasons for choosing it over alternative methods is in order. First, it is simple and easy to use. Second, it requires a minimal amount of data input. Third, it can be used even when information on customer response is limited. Fourth, the procedure does not require actual price changes in order to estimate the cost-effectiveness of time-of-day pricing. As is explained below, with this method, price changes and customer response are "backed into," given the quantity reduction break-even point required to justify time-of-day pricing. In this manner the method is viable even though there are certain data deficiencies.

DESCRIPTION OF METHOD

First, a break-even point in terms of a required per-customer reduction in peak-period kilowatts is calculated. This represents a point below which it would not be cost-effective to undertake the necessary expenditures to measure consumption in a multi-period pricing arrangement. These expenditures would be necessary since a multi-period pricing arrangement requires a more sophisticated metering system than is employed when electricity prices are the same in high- and low-consumption periods. This break-even point is the ratio of the per-customer annualized incremental cost of metering time-of-day rates to the potential per-kW annualized benefits or savings from employing time-of-day pricing. This ratio is interpreted as the minimum number of kW per customer that must be saved to justify the cost of implementing time-of-day pricing.

This required reduction in kW per domestic or residential customer is translated into a required reduction in kWh per customer and compared with average kWh consumption levels during peak periods for the residential customer class. This comparison yields the percentage reduction of peak-period electricity consumption by customer consumption size that is required if that size customer is to be cost-effectively metered for time-of-day pricing. The percentage reductions in energy consumption are then compared with an assumed range of percentage change in the peak-period price of electricity. These price changes are assumed to be from an initial situation in which the per-kWh price of electricity is the same during high- and low-consumption periods. The result of this comparison is a range of long-run elasticities that would yield the required kW break-even point by consumption size, given the assumed price change (see page 23 for the definition of elasticity).

For example, suppose the calculations result in per-customer kW and kWh breakpoints of -0.36 and -177, respectively, and the required per-customer reduction or saving in kWh represents 32.7 percent of peak-period kWh consumption. When this percentage reduction in peak-period kWh consumption is divided by an assumed peak-period electricity price change of 50 percent, the result is a peak-period own-price elasticity of -0.7 ($-0.7 \simeq -32.7 \div 50$). This says that a 50 percent peak-period price increase would yield the required per-customer reduction of 117 kWh or 0.36 kW if the peak-period own-price elasticity were in fact -0.7. (This example is taken from line 3 of table 7.)

To perform these calculations, we assumed that changes in the off-peak price of electricity do not affect on-peak-period consumption. This implies that this cross-price elasticity is zero. This assumption was made because of a lack of information on the value that this cross-price elasticity should assume.

These long-run elasticities (e.g., -0.7) are then compared to an elasticity which is assumed to represent the maximum customer response to peak-period price changes (in absolute value terms) that can be reasonably expected. That is, if the elasticity of -0.7 in the example is greater (in absolute value) than the maximum peak-period own-price elasticity that is believed to be reasonable for New York residential customers, then that size customer could not be cost-effectively metered for time-of-day pricing. If -0.7 is less in absolute value than the elasticity breakpoint, the average residential customer in that consumption class interval could be cost-effectively metered. In other words, this customer could be expected to reduce peak-period kWh consumption enough to justify the cost of metering his consumption under time-of-day pricing. This comparison is made to illustrate how it can be concluded whether it is reasonable to expect that customers will respond to time-of-day pricing to the degree required to justify the cost of implementing and monitoring time-of-day energy pricing.

In addition to the elasticity assumptions stated above, it was assumed that the elasticity or customer response to time-of-day pricing was constant and invariant with customer size and that total consumption of energy (kWh) in the peak and off-peak periods together remains unchanged.

In order to present our methodology in the most understandable fashion, we performed our analysis on what we term composite utilities. By a composite utility is meant a hypothetical utility that represents the load characteristics and incremental capacity cost figures that are derived by taking simple averages of the corresponding figures for a sample of utilities. The method was applied to both an upstate and downstate composite utility. The sample of upstate utilities comprises the Niagara Mohawk Power Corporation and Rochester Gas and Electric Corporation. The sample of downstate utilities comprises Orange and Rockland Utilities, Inc., Consolidated Edison Company of New York, Inc., and Long Island Lighting Company. The specific figures for each utility are contained in the appendix to this report. Because the composite figures are averages of several utilities' figures, they may not be representative of any particular utility.

The upstate-downstate dichotomy was employed in the analysis in an attempt to account for the major differences in load characteristics among the utility systems in New York State. The choice of utilities for each classification was based on discussions with the New York Department of Public Service (NYDPS). The downstate utilities are predominately summer peaking systems because of air conditioning demand; all of the downstate sample utility systems have experienced system peaks in the summer months for at least 10 years. The upstate utilities are predominately winter peaking systems because of proportionately heavy electrical heating loads; however, Rochester Gas and Electric usually peaks in the summer. Exceptions to this were the winters of 1968-1969 and 1976-1977, when Rochester Gas and Electric experienced winter peaks.

<u>Benefits</u>

The potential benefits of time-of-day pricing are estimated in section 2. These benefits lie in two areas:

- The reduction in the investment cost and O&M expenses of future additions to generation, transmission, and distribution capacity

- Dollar saving passed through to the customer resulting from a shift to an off-peak-period generating plant with lower running costs than a peak-period generating plant

Of course, these two benefits only approximate the total benefit of implementing time-of-day pricing. The total benefit of such a program should include any change in economic efficiency. A change in economic efficiency comes about because a reduction in future capacity additions and any dollar savings on the consumer's electric bill represent a reallocation of resources. If resources in all other markets (particularly energy markets) are priced according to marginal cost criteria, then implementing an electricity pricing structure that is set according to marginal cost will enhance economic efficiency by forcing the consumer to bear the true cost of his actions. Unfortunately, in a world where most prices are not set according to marginal cost, it is not clear whether a change to marginal cost pricing in one market will improve or detract from economic efficiency. A further complication is the difficulty of estimating the benefits resulting from improvements in economic efficiency. While estimating improvements in economic efficiency is beyond the scope of this study, it is nevertheless important to recognize the full range of implications of any program with the potential to reallocate resources.

The calculated benefits depend on three assumptions:

- First, that the marginal costs of generation and transmission-distribution capacity are not affected by the implementation of time-of-day pricing. This is a strong assumption because it is quite possible that system costs would change when customers shift a portion of their energy consumption from one period to another as a result of time-of-day pricing.

- Second, that the off-peak period has no capacity responsibility.

- Third (for the running cost calculation), that 100 percent of the reduction in peak period energy consumption is shifted to the off-peak period (i.e., none of the energy is conserved).

COSTS

The costs of implementing time-of-day pricing are the expenditure associated with measuring customer response to the time-differentiated pricing structure. These costs (estimated in section 3) include the expenditures necessary to purchase and install the required metering equipment and any annual incremental costs of carrying out the metering function. These metering costs are based on manufacturers' estimates and the experience of utilities experimenting with the metering systems investigated.

CUSTOMER RESPONSE

In section 4, the results of some time-of-day pricing experiments are reviewed. The results are in the form of peak-period own-price elasticities. As mentioned, the results of these pricing experiments are not definitive; therefore, it was necessary to make some assumptions regarding customer response. Specifically, we assumed that the cross-price elasticity of off-peak price-on peak energy consumption is zero and that the own-price elasticity is constant and invariant with customer size. On the basis of these study results, a range of elasticities was assumed that could be reasonably expected from implementing time-of-day pricing in New York State. The midpoint of this range was chosen as the elasticity breakpoint for use in assessing the economic feasibility of time-of-day pricing in section 5.

A MORE COMPLETE THEORETICAL APPROACH

If more complete information were available on customer responses (i.e., elasticities) our method of assessing the economic feasibility of implementing time-of-day pricing could be expanded to incorporate the cross-price effects. A complete set of elasticities (shown below) would include the own-price coefficients E_{11} and E_{22}, where E_{11} represents the effect of a change in the on-peak-period price on peak-period consumption, and E_{22} the effect of a change in the off-peak-period price on off-peak consumption. A complete set would also include the cross-price elasticities of E_{12} and E_{21}, where E_{12} is the off-peak-price on-peak-consumption elasticity; and E_{21} represents the on-peak-price, off-peak-consumption elasticity. (The first subscript refers to quantity and the second subscript refers to price, in which a subscript of 1 means peak-period and 2 means off-peak-period.)

The following equations detail the relationships involved when cross-price effects are taken into account. Italicized letters indicate percentage change; the subscripts are as explained above. A q refers to the percentage change in kWh consumption and a p refers to the percentage change in electricity price.

$$q_1 = E_{11} \cdot p_1 + E_{12} \cdot p_2 \quad (1)$$

$$q_2 = E_{21} \cdot p_1 + E_{22} \cdot p_2 \quad (2)$$

Equation (1) says that the percentage change in peak-period kWh consumption (q_1) is equal to the percentage change in peak-period price (p_1) times the own-price elasticity (E_{11}) plus the percentage change in off-peak price (p_2) times the cross-price elasticity (E_{12}). Equation (2) is interpreted in a similar manner for percentage changes in off-peak kWh consumption (q_2).

Dividing equation (1) on both sides of the equal sign by p_1 yields equation (3):

$$\frac{q_1}{p_1} = E_{11} + E_{12} \cdot \frac{p_2}{p_1} \quad (3)$$

In this form, equation (3) represents the mathematical equivalent of the elasticity employed in the method outlined in this report where equation (3) was simplified by assuming E_{12} equalled zero. Another way to interpret the elasticity we used in our methodology is that it represents the cross-price effect as well as the own-price effect, which is the equivalent of equation (3).

By manipulating equations (1) and (2), a similar analysis can be performed that incorporates the value of cross- and own-price effects. Equations (4) and (5) show the mathematical form the elasticity model adopts when the required cost-effective peak-period kWh reduction is combined with a derived set of elasticities.

$$p_1 = N_{11} \cdot q_1 + N_{12} \cdot q_2 \tag{4}$$

$$p_2 = N_{21} \cdot q_1 + N_{22} \cdot q_2 \tag{5}$$

The elasticities (N_{ij}) are derived by inverting the matrix of E_{ij} elasticities. With a required value for q_1, one can assume a value for q_2, and combine these values with the N_{ij} elasticities to derive the percentage changes in peak-period and off-peak period prices that would yield the required quantity reduction in peak-period kWh consumption.

It is possible with this approach to derive a value for p_2 that is not attainable; that is, the percentage reduction in the off-peak price cannot be more than a 100-percent reduction. If this were to happen, another value could be chosen for q_2 that would yield an attainable p_2.

Once p_1 and p_2 are derived, they can be examined for their reasonableness and effect on any constraints that must be satisfied. With this more complete elasticity information a more thorough examination of the cost-effectiveness of time-of-day pricing would be possible.

Section 2
BENEFITS OF TIME-OF-DAY PRICING

There are basically two benefits of a time-of-day pricing scheme as we have estimated them. The first is derived from the incremental cost of a kW of peak generation, transmission, and distribution capacity that would otherwise have to be added to a utilities system, and the second is the pass-through to the consumer of a reduction in marginal running costs (mostly fuel) that results from a shift in energy consumption from the peak period to the off-peak period.

TOTAL INCREMENTAL CAPACITY INVESTMENT

Table 3 shows the derivation of incremental capacity costs for the upstate and downstate composite utilities. The installed cost is a simple average of the incremental cost of capacity for each utility. Because these figures are averages, they may not be representative of a particular utility's incremental cost of capacity. They should be interpreted as a conglomeration of the incremental cost-of-capacity of several different utilities.

Table 3. INCREMENTAL CAPACITY INVESTMENT, 1978 $/kW

		Upstate Utilities	Downstate Utilities
1.	Generation, Installed[a]	142	212
2.	Transmission & Distribution[b]	142	212
3.	Subtotal[c]	284	424
4.	Reserves for Outages[d]	26	38
5.	Incremental Capacity Investment[e]	310	462

[a] For the downstate utilities figures are a simple average of respective sample utilities figures. Upstate figure is assumed equal to Rochester Gas & Electric's installed marginal cost of generation.
[b] Assumed equal to Line 1.
[c] Line 1 + Line 2.
[d] 18% of Line 1.
[e] Lines 3 + 4, assuming secondary voltage level (losses included) and no capacity responsibility for the off-peak period.

These figures are taken from the marginal cost studies that each utility has on file with the New York Department of Public Service (NYDPS). For the downstate utilities (Consolidated Edison, LILCO, and Orange and Rockland) the incremental cost-of-generation figures are for gas turbines. For the upstate figure, Rochester Gas and Electric's incremental cost-of-generation is assumed appropriate. This figure represents the Value of Contracted Peaking Capacity. Niagara Mohawk's incremental cost-of-generation figure is not used because it is developed through an alternative approach and is not compatible with the other incremental-generation cost figures. The method used to derive this figure has not been analyzed by the NYDPS at this time.

At the suggestion of the NYDPS the transmission-distribution portion of the incremental-capacity costs was assumed to equal incremental generation costs. The per-kW incremental-capacity costs are then the sum of the generation and transmission-distribution figures plus the 18 percent of the generation cost figure required for reserves. The figures in table 3 are appropriate for the secondary voltage level (losses included) and assume no capacity responsibility for the off-peak period.

ANNUAL CHARGE RATE

For comparison with the annual savings in marginal running costs and later with the cost of metering, the incremental cost-of-capacity is annualized by use of a percentage charge rate that is derived in table 4. Table 4 also calculates the annual percent charge applicable to incremental metering investments. Line 5a is the appropriate charge rate for the incremental capacity cost figure and line 5b is the rate for meters. Taxes are assumed applicable to capacity but not to meters.

PEAK-PERIOD HOURS

Table 5 shows the calculation of the appropriate number of hours for the on-peak period. The hours figure is used for the marginal running cost calculation and also to convert the required kW capacity reduction per customer into a required kWh reduction per customer.

The figures in lines 1 through 3 of table 5 are based on a simple average of the utilities' figures. These figures are in turn based on each utility's definition of its own peak period.

ANNUAL CUSTOMER SAVINGS IN MARGINAL RUNNING COSTS

Marginal running costs are the incremental costs covering fuel and operation and maintenance expenses. These costs are calculated for peak and intermediate or off-peak periods and represent an average of the hourly incremental cost for each period. For our purposes, we have used the marginal running costs that were reported by each utility in its most recent marginal cost study on file at the NYDPS.

Table 4. ANNUAL CHARGE (PERCENTAGE)

		Upstate Utilities	Downstate Utilities
1.[a]	Cost of Money[b]	9.38	$ 9.36
2a.	Depreciation, Capacity[c]	4.00	4.00
2b.	Depreciation, Meters[d]	5.00	5.00
3.	Taxes[e]	3.25	5.25
4.	Insurance[f]	0.10	0.10
5a.	Annual Charge, Capacity[g]	16.73	18.71
5b.	Annual Charge, Meters[h]	14.48	14.46

[a] Lines 1-4 are a simple average of the utilities in the sample.
[b] Most recent rate of return to rate base granted by the New York Public Service Commission.
[c] Straight-line, 25 years (NYDPS).
[d] Straight-line, 20 years (NYDPS).
[e] Taxes on real property (marginal cost studies).
[f] Assumed 1/10 of one percent (NYDPS).
[g] Lines 1 + 2b + 3 + 4.
[h] Lines 1 + 2b + 4.

Table 5. HOURS DURING PEAK PERIOD

		Upstate Utilities	Downstate Utilities
1.	Peak Hours/day[a]	15	13
2.	Peak Days/week[a]	5	6
3.	Peak Months/year[a]	6	4
4.	Total Peak Hours[b]	1949	1351

[a] Based on a simple average of the peak periods of each utility as defined by the utility for its Marginal Cost Study.
[b] Line 1 X Line 2 X 4.33 X Line 3.

The annual saving in marginal running costs is a result of the difference between the running cost per kWh for the plants operating on-peak and the plants operating off-peak. (Plants operating off-peak are "base-load" plants, which are more efficient than peaking plants in their use of fuel.) This cost differential times the number of kWh shifted from the peak period to the off-peak period is a cost saving that is passed through to the customer in lower rates because of lower revenue requirements. Table 6 shows the figures for the upstate and downstate marginal running cost calculations. The marginal running costs per kWh (lines 1 and 2) are simple averages of the figures reported in each utility's marginal cost study.

Table 6. ANNUAL CUSTOMER SAVINGS IN RUNNING COSTS

		Upstate Utilities	Downstate Utilities
	Marginal Running Costs		
1.	Peak Period (¢/kWh)[a]	$ 2.65	$ 3.15
2.	Off-Peak Period (¢/kWh)	2.20	2.44
3.	Premium (¢/kWh)[b]	0.45	0.71
4.	Total Peak Hours[c]	1949	1351
5.	Annual Savings in Running Costs ($/kW)[d]	9	10

[a] Figures are a straight average of the respective utility figures from most recent Marginal Cost Study on file with the NYDPS. The individual utility figures are averages of the hourly incremental cost for each period (peak or off-peak).
[b] Line 1 - Line 2.
[c] Line 4, Table 5.
[d] Line 3 x Line 4 ÷ 100.

The calculation of annual savings in running costs per kW is the difference between the peak-period and off-peak-period per-kWh running costs times the number of hours in the peak period. It is possible to use merely hours because a 100 percent load factor is assumed during the peak hours (i.e., the peak period consists of those hours when demand is at or near the system peak). At the suggestion of the NYDPS we have assumed that all of the reduction in on-peak kilowatt-hour consumption is shifted to the off-peak period. That is, we have assumed that none of the on-peak energy is conserved--the consumption of this reduced energy is shifted completely to the off-peak period.

BENEFITS OF TIME-OF-DAY PRICING

Table 7 summarizes the components of the benefits of time-of-day pricing of the upstate and downstate composite utility. Total annual benefits of the downstate and upstate composite utility are estimated to be $96 and $61 per kW, respectively. The footnotes to table 7 identify the source for each figure and the subsequent steps involved to arrive at total annual benefit. The figures in line 5 are subsequently used in section 5 to demonstrate how a comparison with incremental metering costs can determine the cost-effective per-customer kW savings breakpoint for time-of-day pricing.

Table 7. ANNUALIZED BENEFITS OF TIME-OF-DAY PRICING, 1978 DOLLARS PER kW, ASSUMING NO CAPACITY RESPONSIBILITY FOR THE OFF-PEAK PERIOD

		Upstate Utilities	Downstate Utilities
1.	Incremental Capacity Investment (1978 $/kW)[a]	310	462
2.	Annual Charge (%)[b]	16.73	18.71
3.	Annualized Incremental Capacity Investment[c]	52	86
4.	Annual Savings in Running Costs (1978 $/kW)[d]	9	10
5.	Total Annual Benefits (1978 $/kW)[e]	61	96

[a] Line 5, Table 3.
[b] Line 5a, Table 4.
[c] Line 1 X Line 2.
[d] Line 5, Table 6.
[e] Line 3 + Line 4.

Section 3
METERING EQUIPMENT AND COSTS

The costs of installing, operating, and maintaining measuring equipment for time-differentiated pricing are the focus of this section. These costs, when compared with the capacity costs of the upstate and downstate composite utility, will serve as the basis for the required per-customer kW reduction necessary to justify time-of-day pricing.

In order to determine what equipment was available to measure consumption in multi-time periods, a questionnaire was sent more than 15 manufacturers requesting descriptive and cost information on equipment that would be suitable for implementing time-of-day pricing. On the basis of responses received and the quality of information available, four types of metering equipment were chosen for evaluation. It is our belief that this equipment represents what is available now, or will be available in the near future, for measuring time-differentiated consumption. These types of equipment are:

- Type 1: A two-dial kWh meter
- Type 2: A three-dial kWh meter
- Type 3: A two-dial kWh meter and peak-period kW dial
- Type 4: Automatic meter-reading (AMR)
  - a. International Teledata
  - b. General Electric
  - c. American Science and Engeering

EVALUATION CRITERIA AND ASSUMPTIONS

Our criteria for evaluating time-of-day metering options dictated that the equipment be reliable, dependable, capable of measuring quantities suitable for time-of-day pricing, and equipped with certain devices necessary for cost-effective metering.

With time-of-day metering, a more sophisticated piece of equipment than the conventional kilowatt-hour meter is necessary since a timeclock, an actuating device, and at least another dial are essential to the system's operation. Initial experience with available time-of-day meters indicates that they are reliable and durable, though probably not as reliable and durable as conventional meters. The existing residential meter is virtually maintenance-free; a significant number of them have been in operation for as long as 50 years. Conventional meters are usually depreciated over 30 years. Since there are more moving parts on the time-of-day meters the probability of mechanical failure is greater. Also, potential technology changes may render these meters obsolete. We therefore assume the economic life of time-of-day meters to be 20 years.

Since it is necessary to identify a consumer's electric consumption according to designated periods, the meters considered are capable of measuring kWh and/or kW for specified time periods.

Certain equipment elements were considered essential for time-of-day metering equipment. Battery carryover capability, in the event of power outages, is a critical device. This represents an additional investment over a meter without this capability, yet avoids significant resetting costs every time a power outage occurs. We have assumed that the annualized difference in purchase price of a meter with battery carryover and that of one without carryover capability is less than or equal to the annual resetting cost incurred by using a less sophisticated meter (given a system-dependent probability of an outage). No attempt has been made to include the cost of battery replacement in the annual costs, although manufacturers suggest this will be required approximately every 6 years.

Each of the meter types chosen is capable of recognizing holidays, weekends, and daylight saving time, which allows a more accurate pricing reflection of customer usage and saves reprogramming costs attributable to seasonal time changes. Additionally, these meters are reprogrammed by replacement of an electronic chip or magnetic card.

With metering options 1, 2, and 3, it would be necessary to install a new meter on the customer's premises. It is generally believed that the cost of adapting existing equipment would not be cost-effective. With the type 4 automatic meter reading, it would only be necessary to install an encoder on the existing meter, and the major equipment investment would be at the utility's data collection center. The more sophisticated automatic meter-reading systems allow either for an encoder to be placed in the meter or for replacement of the existing meter with an encoded watt-hour meter.

DESCRIPTIONS OF METERING EQUIPMENT

Type 1. Two-Dial kWh Meter

This type of meter measures kWh consumption in two time periods, typically total kWh and peak kWh. Description of this meter is based on Sangamo's MTR 20 time-of-day register and basic watt-hour meter. The switchable dials on the register are controlled by an electronic clock calendar. Specific time periods, holidays, and weekends are preprogrammed on magnetic cards, replaceable at a cost of approximtely $5 each. Manual meter reading is required. Battery carryover is designed for 35 days with an operating lifespan of 6 to 10 years. The manufacturer indicates no routine annual maintenance is necessary. Battery replacement every 6 or so years will be required; the batteries cost approximately $5 each.

Type 2. Three-Dial kWh Meter

Peak kWh, total kWh, and intermediate or shoulder-peak kWh can be measured by these meters. Both Sangamo (Model MTR 30 time-of-day register) and General Electric (Model IR 70 time-of-day watt-hour meter) produce meters capable of three-dial kWh measurement.

Type 3. Two-Dial kWh with kW Demand

Measurement of total kWh, peak kWh, and maximum peak kW is possible with this type of meter. Sangamo's Model MTR 21 register with a basic watt-hour meter and General Electric's Type IRM 70 watt-hour demand meter are designed to measure these quantities.

Type 4. Automatic Meter-Reading (AMR)

Automatic meter-reading is part of a flexible, two-way communication system, and is designed with varying capabilities and specifications. Basically, a two-way communication system allows information and directive flows between main station equipment located at the utility, which usually serves as a data accumulation center, and a meter located on a customer's premises. Load management, automated distribution, meter-reading, and recognition of multi-periods for time-of-day metering are typically major components of such systems.

It is difficult to generalize about these systems because they are so varied and have yet to be applied on a large-scale basis. However, to consider a two-way communication system for purposes of automatic meter-reading alone represents a denial of its other, inherent capabilities. The value of these systems is their overall features, which should be considered together as a complete package.

Several manufacturers are designing and producing two-way communication systems of differing capabilities. General Electric, Westinghouse, Derco, Porta Systems, International Teledata, and American Science and Engineering are some of the manufacturers providing systems with these capabilities. Our choice of systems to compare was based on their relative degree of sophistication and the amount of readily available information.

International Teledata

The first system, produced by International Teledata of Las Vegas, Nevada, is relatively simple, designed primarily for automatic meter-reading and diagnostic techniques over telephone company lines. The system is of a scanning type, measuring the resistance value at each meter caused by placement of an encoder on the meter. Measured values are read by a multiplexer (located at the telephone company's main office) which is capable of interrogating 10,000 lines in 30 seconds. All system data collection and storage occurs in the computer located at a utility.

International Teledata's system is being experimentally applied to large industrial customers by the municipal electric utility of the City of Burbank, California. Experimental residential applications are being implemented at Laguna Beach, California, for both gas and electric utilities.

General Electric

General Electric has designed an automatic meter-reading and automated distribution system that is significantly more sophisticated than the International Teledata equipment. As a load management and distribution device it is intended to improve an electric utility's load factor and additionally provide communications to enhance distribution system reliability and cost-effectiveness. Although time-of-day metering is an integral part of the system's capabilities, its primary value is realized through utilization of all of its components.

Communication between the meter terminal unit (MTU), located at a customer's premises, and a reading control center (RCC) at the utility's office is via distribution lines. A substation control unit (SSCU) provides the interface between the MTU and the RCC, receiving, decoding, and retransmitting messages from the latter. A section control unit (SCU), located at the neighborhood level, performs a store-and-forward function for messages received from the SSCU. These components, along with those necessary for automated distribution and load management, form the heart of the system.

American Science and Engineering

A sophisticated powerline carrier system capable of local control and multirate metering produced by American Science & Engineering, Inc., (ASE) was also investigated. It is a two-way system, with full dynamic control of all metering functions from a central location. All metering data are retrieved remotely and automatically over the powerlines. The system works in much the same way as the General Electric Amrac system. The key components of the ASE system include a data dispatch controller designed to monitor and control system operations; a substation communications unit, which receives signals originating with the data dispatch controller, that have been sent via dedicated telephone lines, and retransmits these signals over the utility distribution lines to transponders and load control receivers. Alternately, it retransmits information received from transponders back to the data control center. The transponders act as transmitters and receivers at each two-way point and serve to accept control signals, read and store metering data, and transmit status data back to the data dispatch controller. A multirate metering module with three separate nonvolatile, 24-bit memories, is located in the transponder.

ASE systems have been tested by General Public Utilities, Jersey Central Power & Light, San Diego Gas & Electric, and the Wisconsin Power & Light Company system. Northern States Power, Florida Power & Light, Florida Power Corporation, and Springfield Electric have also had experience with the ASE system. The equipment is said to be available as a complete system in operation 6 months from receipt of order.

Other

Several other metering options, including magnetic tape systems, were also investigated. Basically, such systems have significantly more capability than simple multiperiod consumption recording and are considerably more expensive than the equipment described in types 1-4. It was determined that magnetic tape systems were too costly to justify implementation on a large scale and therefore were not included in the analysis.

In theory, a utility could retrofit existing meters with additional kWh and kW registers to accomplish time-of-day capability. However, without knowledge of a utility's equipment and cost characteristics, the costs of this could not be estimated for use in this analysis.

COST EVALUATIONS

Our metering cost analysis relies primarily on information received from manufacturers and on discussions with several utilities with some time-of-day pricing experience. Purchase cost estimates are manufacturer's quoted prices and, where applicable, include price discounts for volume orders. The principal information sources for installation and annualized incremental costs were utility contacts and assumptions based upon these contacts.

To date, experience with time-of-day metering is limited to recent experiments and partial implementation. Since multiperiod pricing is relatively new in the United States, most equipment that is designed for this application here has either been introduced recently or is still in the experimental phase. As a result, estimates of detailed cost characteristics are generally not available and probably not representative of the ultimate operating costs of the equipment. This is common when introducing a new technology or product. The more units that are produced, the lower the cost of each unit because fixed costs are spread out over a larger number of units. Because of this it should be realized that, although our analysis is based upon the best information made available to us, the estimated costs are only indicative of those which a utility might incur when implementing time-of-day pricing.

Descriptions of each metering type and their corresponding cost estimates are included in table 8. Equipment purchase costs are based on manufacturers' estimates (either General Electric's or Sangamo's for types 1, 2, and 3). Quoted purchase costs were identical for both manufacturers. Type 4 equipment costs are based on estimates by International Teledata, General Electric, and American Science & Engineering, Inc. The cost of implementing alternative time-of-day pricing schedules will vary, however, since the costs of basic metering equipment, labor installation, service areas, operation and maintenance, and the overall objectives of metering will vary among utilities.

Table 8. COMPARISON OF ANNUALIZED COSTS FOR TIME-OF-DAY METERING (1978 $/METER)

	Note	(1) Type 1	(2) Type 2	(3) Type 3	(4) Type 4	(5) Type 5	(6) Type 6
			Meters			Automatic Meter Reading	
		Two-Dial kWh	Three-Dial kWh	Two-Dial kWh W/Peak kW	Int'l Teledata	General Electric	American Science
Investment Costs							
1. Purchase[a]	A	130	145	240	36	197-242	167
2. Installation[b]	B	20	20	20	20[1]	N.A.	20[h]
3. Total Initial Investment[c]	C	150	165	260	56	--	187
Incremental Annual Costs							
4. Maintenance[d]	D	10	12	15	1	N.A.	1
5. Reading & Processing[e]	E	3	3	4	--	N.A.	(6)
Annualized Investment Cost							
6a. Average Downstate[f]	F	22	24	38	8	--	27
6b. Average Upstate[f]	F	21	24	37	8	--	27
Annualized Total Incremental Costs							
7a. Average Downstate[g]	G	35	39	57	9	--	22
7b. Average Upstate[g]	G	34	39	56	9	--	22

[a] Based on manufacturer's estimates.
[b] Assumes $20 installation costs for downstate utilities and $17 for upstate utilities to account for wage differentials.
[c] Line 1 + Line 2.
[d] Assumes annual maintenance cost of conventional meter equals zero. Based on a West Coast utility's estimates for time-of-day metering equipment.
[e] Columns 1-3 based on a West Coast utility's estimates and an estimate of $2/year for reprogramming costs. Column 5 is net of an upstate New York utilities estimate of $6.90 for existing meter-reading and processing costs minus manufacturer's estimate of .75¢ for same and assumed annual line leasing cost of $6.00/meter.
[f] Line 3 x Line 5b, table 4.
[g] Line 4 + 5 + 6.
[h] Installation of encoder at meter only. Software installation included in purchase costs.

Installation

Estimates for installation, loading, and paperwork associated with each meter installation for upstate are based on estimates by an upstate New York utility of the costs for conventional watt-hour meter installation; for downstate utilities, they are based on the same estimates but adjusted for wage differences in the two labor market areas. It is assumed that the cost of installing time-of-day equipment, including automatic meter-reading equipment, is not appreciably different from that for replacing a conventional meter.

Incremental Maintenance

Because time-of-day meters are more complex, involving more moving parts, maintenance costs are likely to be higher than for a conventional meter (especially since the conventional meter is almost maintenance-free). Maintenance costs are based on estimates made by West Coast utility for a cost analysis of the various types of time-of-day metering equipment.

Incremental Meter Reading and Processing

Compared with existing meters, the additional meter reading costs have been assumed to be negligible although there will be more dials to read, record, and bill. For meter types 1, 2, and 3, the estimate used for incremental cost is again based on the West Coast utility's analysis. The cost differentials assoiated with automatic metering were derived by subtracting the estimated costs provided by International Teledata from the estimated meter reading, processing, and billing costs for upstate and downstate New York utilities.

Telephone Line Lease

The cost associated with telephone line leasing for the International Teledata system assumes that line leasing costs equal meter reading costs. However, these costs may vary considerably depending upon the agreement reached between electric utility and the telephone company. Therefore, there is a lesser degree of certainty regarding the International Teledata cost estimate than with the other metering systems.

Annualized Investment Costs

Annualized investment costs are based upon an assumed equipment life of 20 years. The appropriate annual charge rate is shown on line 5b of table 4.

Automatic Meter-Reading Equipment Considerations

Purchase costs per meter for the International Teledata system include:

- All hardware
  - Computer
  - Communications equipment
  - Multiplex equipment
  - Encoders and sensors

- Software for full system operation

- Engineering and installation supervision

Cost estimates are based on a minimum order of 100,000 units. Installation costs at the meter are borne by each utility and line use charges are determined by the telephone company.

Purchase cost estimates for the General Electric system include:

- Completely encoded single-phase meter

- Meter terminal unit

- Distribution line carrier communications equipment and carrier coupling equipment

- Reading/control center equipment, necessary software, and installation engineering service, and recommended test equipment

Estimates of installation, maintenance, and meter-reading and processing costs were unavailable for the General Electric System.

According to the manufacturer, over the long-run the cost of a complete typical 100,000-point system produced by American Science & Engineering, installed with a time-differentiated energy rate metering transponder and a single-load control unit, will be the $125 to $200 range. This includes prorated cost of central computer and substation communications equipment. The estimates of cost presented in table 8 are based on recent testimony and exhibits prepared for the Wisconsin Public Service Commission by Arthur D. Little, Inc., of Cambridge, Massachusetts. The costs reflect the equipment necessary to convert the Madison Gas & Electric Company network to time-of-day metering capability. It assumes an 80,000-meter-point installation. Equipment costs include:

- A standard watt-hour meter

- A transponder

- A device for adapting a standard meter to the ASE transponder and injection system

Installation costs include:

- Installation of meter adapter (in shop)

- Installation of modified meter

- Installation of transponder

- Equipment handling, shop testing, records

Maintenance costs are estimated per meter for the cost of maintaining one meter and one receiver per customer, plus annual maintenance associated with the injection system.

Meter reading and processing costs are assumed to be approximately $1 per year, resulting in a net savings of $6 (given the estimated annual cost of reading existing meters for a New York upstate utility).

Estimates of the annualized incremental cost of metering were estimated on the basis of this information and these assumptions. These costs are listed on lines 7a and 7b of table 8 for the downstate and upstate composite utility.

Table 8 indicates that the International Teledata automatic meter reading systems annualized incremental cost of $9 is the least costly of the systems investigated. This figure is less than the annualized incremental cost figures for types 1, 2, and 3 which range from $34 to $57. While every effort was made to secure accurate information and we strongly believe that all the information from the manufacturer was supplied in good faith, there is some doubt as to the accuracy of this number. It may be an accurate representation of the annualized incremental cost of the International Teledata automatic metering system but several sources indicate that it is too low. The suspicion that the number is too low is furthered by the large difference between it and the other cost figures which range from $22 to $57. Also, the telephone line lease component of this cost figure is not as firm as the other components because its actual value depends on telephone company cooperation. Therefore, any use or interpretation of results derived from the use of the $9 figure should be done with the understanding that the accuracy of the number is believed to be in doubt by the authors of this report.

Section 4
CUSTOMER RESPONSE TO TIME-OF-DAY PRICING

In order to assess the economic feasibility of implementing time-of-day pricing, our method requires some idea of how much consumers can be expected to respond to a change in the peak period price of electricity. Since our analysis does not involve an actual time-of-day pricing experiment, we have investigated the responses (in terms of peak-period elasticities) of time-of-day pricing experiments that have been conducted in other parts of the country.

SHORT-TERM ELASTICITY

Our analysis relies heavily on the direct testimony of William B. Shew, which was submitted to the NYDPS in case No. 27319. The Shew testimony identifies 47 experiments that pertain to time-of-day pricing for the residential customer class. Of these, five derived some type of customer response to time-of-day pricing. Table 9 summarizes these studies and table 10 lists those studies which yielded undetermined results. Unfortunately, only two of these studies derived actual peak-period own-price elasticities.

The peak-period own-price elasticity is defined as the percentage change in peak-period kWh consumption divided by the percentage change in peak-period price. In general terms, own-price elasticity is the change in the consumption of commodity Q divided by the original amount of commodity Q consumed, over the change in the price of commodity Q divided by the original price of commodity Q, as follows:

$$\frac{\Delta Q/Q}{\Delta P/P}$$

Cross-price elasticity is defined as the change in the consumption of commodity Q divided by the original amount of Q consumed over the change in the price of another commodity (Y) divided by the original price of commodity Y, as follows:

$$\frac{\Delta\ Q/Q}{\Delta P_Y/P_Y}$$

The two experiments that actually derived estimates of peak-period own-price elasticity are the Arizona Public Service Commission study and the study conducted by Connecticut Light and Power. In the Arizona experiment, peak-period own-price elasticity estimates range from -0.62 to -079 according to one researcher, and from +0.25 to +0.41 according to another. The positively signed elasticities were not statistically different from zero and are therefore not judged suitable for this analysis. For the Connecticut experiment, estimates range from -0.21 to -0.66.

These two experiments suffer from several drawbacks. Generally, the experiments were not conducted under ideal circumstances. Both were of a short duration (5 to 12 months), and participation in both was strictly voluntary. The implications of these two facts are important.

Table 9. SUMMARY OF LOAD MANAGEMENT EXPERIMENTS OUTSIDE OF NEW YORK STATE THAT YIELDED ESTIMATES OF CUSTOMER RESPONSE TO TIME-OF-DAY PRICING

Utility	Rate Description	Incentive	Sample Selection	Study Length	Results: Taylor[a]	Results: Atkinson
Elasticity Results:						
Arizona PSC	3-part kWh rate in three sets of time periods	none	volunteer	5 months	GR I +0.41 GR II +0.04 GR II +0.25	-0.62 -0.79 -0.71
Connecticut L&P[b]	6-part kWh rate seasonal	∿25% of avg annual bill paid	volunteer	12 months	H&H: -0.3 L&B: -0.21 - -0.66 short run peak period Granger: 0.12 kW per customer reduction in peak	
kW Reduction Results:						
Georgia Power Co.	1. 2-part season kWh rate	none	mandatory	24 months	At summer peak load in test group was 0.95 kW per customer lower than control group	
	2. kW charge 5 part declining block; kWh charge	none	mandatory	24 months	At summer peak load in test group exceeded control by ∿1.0 kW per customer Demand in test group exceeded load of control group during each hour of day on system summer peak	
	3. seasonal 2-part kW rate, flat kWh charge, off season; 2-part kWh charge, on season	none	mandatory	24 months	At summer peak load was 0.33 kW lower per customer than test group	
Florida Power Corp.	Declining 2-part kWh block rate for peak & off period	Co. pd. half $ of time clock	volunteer	12 months	Test group load was 0.56 kW per customer less than control group	
Northern States Power	Fixed charge; on & off-peak kWh charge according to zone	$100 pd @ beginning	random	12 months	Average kW demand for exp. group was 73% lower than test at system winter peak of 72% of test for overall system peak (summer)	

[a] Taylor's elasticities not statistically significant.

[b] Insufficient variation in price; study cannot be regarded as reliable.

Table 10. FIRMS CONDUCTING TIME-OF-DAY EXPERIMENTS WHICH YIELDED UNDETERMINED RESULTS

Green Mountain Power (four experiments)
Central Vermont Public Service Company
Public Service Company of New Hampshire
Granite State Electric
Exeter and Hampton Electric
Connecticut Valley Electric Company, Inc.
Concord Electric Company
New Hampshire Electric Cooperative, Inc.

First, the relatively short time span of the experiments suggests that the estimated elasticities indicate short-term responses only. Because a consumer is usually unable to fully respond within 1 year to a change in a particular economic variable, the short- and long-run elasticities are bound to be different, with the long-run elasticity greater in magnitude. For purposes of assessing economic feasibility, the long-run or ultimate customer response to time-of-day pricing is needed. That is, it is the permanent reduction in demand that is the objective of implementing a time-of-day pricing scheme.

Second, the implication of an all-volunteer experiment is that, on the average, people will not respond in the same manner as they would if participation were mandatory. For example, in many time-of-day pricing experiments cash was provided to consumers at the beginning of the experiment. The cash was to cover any increases in the customer's electric bill resulting from participation in the experiment. That is, if the customer's bill were higher than it would have been with constant rates, the customer was held blameless because the utilities' cash contribution covered the increase in the bill. This has the effect of weakening the customer response to higher prices and implies a smaller own-price elasticity (in absolute value).

A comprehensive critique of these previous time-of-day experiments is beyond the scope of this study. Their more salient limitations are outlined to convey a more accurate picture of them, so as to facilitate interpretation of the results of our test cases (section 5). That is, the results of the test cases are sensitive to the reasonableness of the range of elasticities that we have assumed as appropriate bounds by which to judge the New York situation.

Even though the elasticity estimates reported for the Arizona and Connecticut studies were not derived under ideal circumstances, they still indicate what magnitude a short-term elasticity (within 1 year) can be expected to assume. From the results of these two experiments, we have assumed -0.3 to -0.7 as a range within which the true short-run peak-period own-price elasticity would fall. To derive a single estimate of the peak-period price-peak period consumption elasticity from the results of these studies, the following assumptions were made:

- The own-price elasticity is constant and invariant with economic factors
- The off-peak-period price on-peak-period kWh consumption cross-price elasticity is equal to zero (this is assumed because of a lack of information on what values it might assume)
- The load characteristics of the New York power systems are not sufficiently different from those in Arizona and Connecticut to make the -0.3 to -0.7 range inapplicable to New York

LONG-RUN ELASTICITY

In assessing the economic feasibility of time-of-day pricing, it is the permanent or long-term reduction in capacity additions that should be considered. Since the existing estimates of peak-period own-price elasticities are for short-term responses, it is necessary to adjust these to reflect long-term or permanent customer responses to the implementation of time-of-day rates. To make this adjustment, a technique commonly used in econometrics has been employed. With this technique, a lag parameter is used to convert short-run elasticities to long-run elasticities.

What is required are assumptions regarding the mathematical form the lag parameter follows and the number of years it takes before 100 percent of the total customer response to the price change is completed. For our purposes we have assumed a geometric lag structure, a common assumption employed in many existing load forecasting models. At the suggestion of the NYDPS, we have assumed that a period of 7 years is required to complete 100 percent of the customer reaction to a change in the price of peak-period energy.

Table 11 details the annual distribution of customer responses for a 7-year lag parameter, and table 12 shows the short- and long-term elasticities determined from existing time-of-day pricing experiments. For purposes of assessing economic feasibility in the test cases in section 5, it has been assumed that the midpoint of the range of long-run elasticities bounded by -0.6 and -1.3 is the breakpoint below which the elasticities derived must fall. That is, the elasticities that result from the cost-effective breakpoint calculations (see tables 13 through 22) must be less than -0.9 in magnitude (or absolute value) if cost-effectiveness is to be achieved.

Table 11. DISTRIBUTION OF CUSTOMER RESPONSE THROUGH TIME, ASSUMING 7 YEARS REQUIRED FOR TOTAL RESPONSE TO BE COMPLETED

Year	Annual Customer Response as a Percent of Total Response: Annual	Cumulative
1	0.550	0.550
2	0.248	0.798
3	0.112	0.910
4	0.050	0.960
5	0.023	0.983
6	0.010	0.993
7	0.005	1.000

NOTE: Assumes a geometric lag pattern (lag parameter = 0.45)

Table 12. ELASTICITIES FROM EXISTING STUDIES

Range	Short-Run[a]	Long-Run[b]
Low	-0.3	-0.6
High	-0.7	-1.3

[a] Estimates based on values reported in the Arizona Public Service Commission and Connecticut Power & Light time-of-day pricing experiments.

[b] Short-run elasticity divided by (one minus the lag parameter), Lag Parameter = 0.45.

Section 5
ECONOMIC FEASIBILITY OF IMPLEMENTING TIME-OF-DAY PRICING

In this section the results of sections 2, 3, and 4 are used to demonstrate the method described in section 1. Our method is demonstrated for two test cases: for the upstate composite utility (tables 13 through 17) and the downstate composite utility[1] (tables 18 through 22). The footnotes on each table summarize the method.

DETERMINING ELASTICITIES

The first step is to calculate the required per-customer reduction in peak period demand. The result of this calculation is shown in column 1a of tables 13 through 22. This is a breakpoint below which economic feasibility would not be attained. That is, if the implementation of time-of-day pricing causes the average consumer to permanently reduce his electricity consumption sufficiently to yield at least the kW reduction shown in column 1a, then time-of-day pricing would be economically feasible. The required per-customer kW reduction is determined by dividing the annualized cost of implementing time-of-day metering (line 7 of table 8) by the annualized savings in capacity and running costs (line 5 of table 7).

The figure in column 1b of tables 13 through 22 is the monthly per-customer permanent reduction in peak-period energy consumption during the peak months that is required to justify time-of-day pricing. Since we have defined a peak-period hour as an hour when demand is at or near the system peak, we have assumed a 100-percent load factor during the peak period. (See table 5 for the definition of the peak-period.) Consequently, the required reduction in peak-period energy consumption during peak months is derived by multiplying column 1a by the number of total peak-period hours (line 4, table 5), and dividing by the number of peak months (line 3, table 5) for each region.

Column 2 is a breakdown of customer size classifications for total monthly kWh consumption. The groupings chosen were dictated by the form in which the data were supplied to us by the utilities and roughly conform to the size breakdowns requested by the NYDPS.

To compare the required per-customer peak-period kWh reduction with average peak-period kWh consumption during the peak months, column 2 was adjusted by a factor in the calculations to reflect the distribution of peak-period energy consumption instead of a distribution of monthly energy consumption. On the basis of the data received from the upstate and downstate utilities, we assumed that, for upstate utilities, 55 percent of energy consumed by a residential customer during the peak months was consumed during on-peak hours. For downstate utilities, this figure was assumed to be 45 percent. From the data analyzed, the distribution of

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[1] Test case results have been summarized in tables 1 and 2.

on-peak energy as a percent of total monthly energy did not show any discernible pattern relative to customer kWh consumption. Therefore, we assumed that these percentages were representative of the relative distribution of on-peak and off-peak energy consumption characteristic of both small and large residential customers. For upstate utilities, the data showed that between 51 and 60 percent of energy consumed during the peak months was consumed during on-peak hours. For downstate utilities, the range is 39 to 50 percent.

Column 3 of tables 13 through 22 shows the percentage reduction by consumption class interval that the required reduction in energy represents. This is calculated by dividing column 1b by the midpoint of column 2, adjusted to reflect the percent of monthly energy consumption consumed during on-peak hours.

Columns 4a and 4b are the result of dividing the percentage change in peak energy consumption in column 3 by 10 percent and 50 percent, respectively. These two columns represent (in magnitude) the required long-run elasticities that must be attained for each consumption size interval, given the 10- and 50-percent peak-period price increases, if time-of-day pricing is to be economically feasible. Using line 3 of table 13 as an example, the calculation of the required long-run elasticities is as follows:

$$\text{Percent change in quantity} = -50.9$$
$$\text{Percent change in price} = 50.0$$

$$\text{Required long-run elasticity} = \frac{-50.9}{50.0} \sim = -1.0$$

A required long-run elasticity of -1.0 means that consumers in the 501 to 800 kWh per month range can be cost-effectively metered given a 50-percent peak-period price increase only if the peak-period own-price elasticity is greater than or equal to -1.0 in absolute value. Similarly, for a 10-percent price increase, the customers in the 501 to 800 kWh per month range could be cost-effectively metered if the peak-period own-price elasticity were greater than or equal to -5.1 in absolute value.

For example, table 20 shows that a downstate composite utility customer with an average monthly consumption of 1,001 kWh or more during the peak months could be cost-effectively metered, given a 50-percent price increase. For customers of 1,001 kWh or more, elasticities of -0.7 down to -0.3 (largest consumption class) would be required for cost-effective metering. Since these values fall below the -0.9 derived in section 4, the analysis shows that for these customers time-of-day pricing could be introduced cost-effectively. For consumers below a 1,001-kWh month, the breakeven elasticities exceed the elasticity value that we assume can reasonably be expected (-0.9). Therefore, these customers cannot be cost-effectively metered for time-of-day pricing.

The range of 10 to 50 percent for peak energy price increases was assumed on the basis of the various peak-period energy price increases in the Arizona and Connecticut time-of-day experiments discussed in section 4. Most price increases in these two studies, as well as others, fell within 10 and 100 percent, although some were less than 10 percent.

For each region the same average incremental capacity investment figure is compared (column 1a of tables 18 through 22) with each of the four types of metering equipment cost figures. This yields a different kW breakpoint for each metering scheme and for each region. Consequently, the required long-run elasticity varies by region--i.e., by incremental capacity investment and by type of meter. For both the upstate and downstate regions the same procedure is employed (columns 4a and 4b) to determine by region and meter type the size of customer (by kWh consumption) that would be required in order to introduce time-of-day pricing cost-effectively.

REQUIRED ELASTICITIES

Upstate

For the upstate composite utility, tables 13 through 17 illustrate how our method can determine the required elasticities by customer consumption size for each of the meters investigated (based on the data and assumptions presented in sections 1 through 4).

Table 13 shows that a two-dial kWh meter in upstate New York would require a customer size of at least 3,677 kWh per month during the peak months, given a 10-percent price increase. This represents less than 1.4 percent of total residential customers. The kWh consumption figure was calculated by inserting the assumed values of -182 kWh, elasticity of -.9, the adjustment factor of 0.55 that reflects the percent of monthly kWh consumption during peak hours, and the price change of +10 percent into the formula for elasticity, as follows:

$$-.9 = \frac{-182/(Q\cdot.55)}{.10}$$

Solving this equation yields $Q = 3,677$ kWh per month as the minimum-size customer who could be cost-effectively metered with an elasticity of -.9 and a 10-percent price increase. At a 50-percent price increase, all customers who consume in excess of 801 kWh per month could be cost-effectively metered for time-of-day pricing (16.1 percent of customers). This is because the required long-run elasticities are all less than -.9 in absolute value for customers in the consumption classes greater than 801 kWh. An elasticity lower in absolute value than -.9 indicates that the reduction in kWh consumption required to justify time-of-day pricing for that size customer class is less than the maximum kWh reduction attainable given the percentage increase in price and the value of elasticity parameter that can be expected.

With the three-dial kWh meter (table 14) only those consumers who consume in excess of 4,202 kWh per month during the peak months can be cost-effectively metered at a 10-percent peak-period price increase. This represents less than 1.4 percent of total residential customers.

Table 13. UPSTATE UTILITIES: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR TWO-DIAL kWh METER (ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY)

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer			Required Change in Peak Energy Consumption	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval
kW	kWh	Consumption Size (kWh/month)	(%)	10%	50%	(%)
-0.56	-182	0-250	-264.7	-26.5	-5.3	29.0
-0.56	-182	251-500	-88.2	-8.8	-1.8	31.9
-0.56	-182	501-800	-50.9	-5.1	-1.0	21.8
-0.56	-182	801-1,000	-36.8	-3.7	-0.7	6.8
-0.56	-182	1,001-1,500	-26.5	-2.7	-0.5	6.3
-0.56	-182	1,501-2,000	-18.9	-1.9	-0.4	1.6
-0.56	-182	2,001 & Over	-10.2	-1.0	-0.2	1.4

Table 14. UPSTATE UTILITIES: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR THREE-DIAL kWh METER (ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY)

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer			Required Change in Peak Energy Consumption	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval
kW	kWh	Consumption Size (kWh/month)	(%)	10%	50%	(%)
-0.64	-208	0-250	-302.5	-30.3	-6.1	29.0
-0.64	-208	251-500	-100.8	-10.1	-2.0	31.9
-0.64	-208	501-800	-58.1	-5.8	-1.2	21.8
-0.64	-208	801-1,000	-42.0	-4.2	-0.8	6.8
-0.64	-208	1,001-1,500	-30.3	-3.0	-0.6	6.3
-0.64	-208	1,501-2,000	-21.6	-2.2	-0.4	1.6
-0.64	-208	2,001 & Over	-11.7	-1.2	-0.2	1.4

NOTES

Column:

1a	**Line 7 (table 8) ÷ line 5 (table 7)**
1b	**Column 1a x line 4 (table 5) ÷ line 3 (table 5)**
2	**Breakdown corresponds to format of available data**
3	**Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities**
4a	**Column 3 ÷ 10**
4b	**Column 3 ÷ 50**
5	**From billing frequency distributions for each sample utility**

Table 15. UPSTATE UTILITIES: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR TWO-DIAL kWh-PEAK kW METER (ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY)

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer			Required Change in Peak Energy Consumption	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval
kW	kWh	Consumption Size (kWh/month)	(%)	10%	50%	(%)
-0.92	-299	0-250	-434.9	-43.5	-8.7	29.0
-0.92	-299	251-500	-145.0	-14.5	-2.9	31.9
-0.92	-299	501-800	-83.6	-8.4	-1.7	21.8
-0.92	-299	801-1,000	-57.2	-5.7	-1.1	6.8
-0.92	-299	1,001-1,500	-43.5	-4.4	-0.9	6.3
-0.92	-299	1,501-2,000	-31.1	-3.1	-0.6	1.6
-0.92	-299	2,001 & Over	-16.6	-1.7	-0.3	1.4

Table 16. UPSTATE UTILITIES: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR AUTOMATIC METER-READING (INTERNATIONAL TELEDATA) ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer			Required Change in Peak Energy Consumption	Required Peak Period Elasticity Given a Peak Price Increase of		Total Customers in Class (%)
kW	kWh	Consumption Size (kWh/month)	(%)	10%	50%	Total Residential
-0.15	-49	0-250	-71.3	-7.1	-1.4	29.0
-0.15	-49	251-500	-23.8	-2.4	-0.5	31.9
-0.15	-49	501-800	-13.7	-1.4	-0.3	21.8
-0.15	-49	801-1,000	-9.9	-1.0	-0.2	6.8
-0.15	-49	1,001-1,500	-7.1	-0.7	-0.1	6.3
-0.15	-49	1,501-2,000	-5.1	-0.5	-0.1	1.6
-0.15	-49	2,001 & Over	-2.8	-0.3	-0.1	1.4

NOTES

Column:

1a	**Line 7 (table 8) ÷ line 5 (table 7)**
1b	**Column 1a x line 4 (table 5) ÷ line 3 (table 5)**
2	**Breakdown corresponds to format of available data**
3	**Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities**
4a	**Column 3 ÷ 10**
4b	**Column 3 ÷ 50**
5	**From billing frequency distributions for each sample utility**

Given a 50-percent price increase, those customers consuming in excess of 801 kWh per month (16.1 percent) could be metered cost-effectively.

A two-dial meter that also measures peak demand (table 15) would require a customer who consumed at least 6,040 kWh per month during the peak period, given a 10-percent price increase, and at least 1,001 kWh per month at a 50-percent price increase. At a 10-percent price increase, less than 1.4 percent of residential customers could be metered cost-effectively, but the figure rises to 9.3 percent with a 50-percent price increase.

With the International Teledata automatic meter-reading system (table 16), 69.8 percent of the customers could be metered cost-effectively, given a 50-percent or greater price increase, and 9.3 percent, given a 10-percent price increase. The kWh breakpoints would be 1,001 and 251 kWh per peak month, respectively, for the 10-percent and 50-percent price increases.

With the American Science and Engineers automatic meter-reading system (table 17), only those customers consuming in excess of 2,001 kWh per month could be cost-effectively metered, given a 10-percent price increase. This represents 1.4 percent of the total residential customer class. At a 50-percent price increase, 37.9 percent of residential customers (those whose average monthly consumption is in excess of 501 kWh) could be cost-effectively metered.

Table 17. UPSTATE UTILITIES: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR AUTOMATIC METER-READING (AMERICAN SCIENCE AND ENGINEERING) ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer			Required Change in Peak Energy Consumption	Required Peak Period Elasticity Given a Peak Price Increase of		Total Customers in Class (%)
kW	kWh	Consumption Size (kWh/month)	(%)	10%	50%	Total Residential
-0.36	-117	0-250	-170.2	-17.0	-3.4	29.0
-0.36	-117	251-500	-56.7	-5.7	-1.1	31.9
-0.36	-117	501-800	-32.7	-3.3	-0.7	21.8
-0.36	-117	801-1,000	-23.6	-2.4	-0.5	6.8
-0.36	-117	1,001-1,500	-17.0	-1.7	-0.3	6.3
-0.36	-117	1,501-2,000	-12.2	-1.2	-0.2	1.6
-0.36	-117	2,001 & Over	-6.6	-0.7	-0.1	1.4

NOTES

Column:

1a Line 7 (table 8) ÷ line 5 (table 7)

1b Column 1a x line 4 (table 5) ÷ line 3 (table 5)

2 Breakdown corresponds to format of available data

3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities

4a Column 3 ÷ 10

4b Column 3 ÷ 50

5 From billing frequency distributions for each sample utility

Downstate

Tables 18 through 22 illustrate how our method derives the required elasticities for each type of meter, by consumption size, for the downstate composite utility.

Table 18 shows that, for customers with consumption over 2,465 kWh per peak month, a two-dial kWh meter would be cost-effective, assuming a 10-percent peak period price increase. This represents less than 0.8 percent of residential customers. At a 50-percent price increase, those customers consuming 511 kWh per peak month would be cost-effectively metered. This represents 46.8 percent of residential customers.

With the three-dial kWh meter (table 19), the breakpoints are 2,788 kWh at a 10-percent price increase and 751 kWh, given a 50-percent increase. At a 10-percent price increase, this represents less than 0.8 percent of residential customers. At a 50-percent price increase 24.7 percent of residential customers are cost-effectively metered.

Table 18. DOWNSTATE UTILITIES: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR TWO-DIAL kWh (ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY)

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (kWh/month)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Total Customers in Class (%)[a]
kW	kWh			10%	50%	
-0.36	-122	0-240	-225.9	-22.6	-4.5	19.1
-0.36	-122	241-510	-72.3	-7.2	-1.4	34.1
-0.36	-122	511-750	-43.0	-4.3	-0.9	22.1
-0.36	-122	751-1,000	-30.9	-3.1	-0.6	11.4
-0.36	-122	1,001-1,500	-21.7	-2.2	-0.4	8.2
-0.36	-122	1,501-2,000	-15.5	-1.5	-0.3	2.6
-0.36	-122	2,001-2,400	-12.3	-1.2	-0.2	1.0
-0.36	-122	2,401-3,000	-10.0	-1.0	-0.2	0.7
-0.36	-122	3,001 & Over	b			0.8

NOTES

Column:

1a Line 7 (table 8) ÷ line 5 (table 7)

1b Column 1a x line 4 (table 5) ÷ line 3 (table 5)

2 Breakdown corresponds to format of available data

3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities

4a Column 3 ÷ 10

4b Column 3 ÷ 50

5 From billing frequency distributions for each sample utility

[a] Customer distributions for residential subclassification are based on LILCO's customer distribution for each subclass.

[b] Insufficient data to perform calculation.

Table 19. DOWNSTATE UTILITIES: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR THREE-DIAL kWh (ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer			Required Change in Peak Energy Consumption	Required Peak Period Elasticity Given a Peak Price Increase of		
kW	kWh	Consumption Size (kWh/month)	(%)	10%	50%	Total Customers in Class (%)[a]
-0.41	-138	0-240	-255.6	-25.6	-5.1	19.1
-0.41	-138	241-510	-81.8	-8.2	-1.6	34.1
-0.41	-138	511-750	-48.7	-4.8	-1.0	22.1
-0.41	-138	751-1,000	-35.0	-3.5	-0.7	11.4
-0.41	-138	1,001-1,500	-24.5	-2.5	-0.5	8.2
-0.41	-138	1,501-2,000	-17.5	-1.8	-0.3	2.6
-0.41	-138	2,001-2,400	-13.9	-1.4	-0.3	1.0
-0.41	-138	2,401-3,000	-11.4	-1.1	-0.2	0.7
-0.41	-138	3,001 & Over	b			0.8

Table 20. DOWNSTATE UTILITIES: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR TWO-DIAL kWh-PEAK kW (ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer			Required Change in Peak Energy Consumption	Required Peak Period Elasticity Given a Peak Price Increase of		
kW	kWh	Consumption Size (kWh/month)	(%)	10%	50%	Total Customers in Class (%)[a]
-0.59	-199	0-240	-368.5	-37	-7.4	19.1
-0.59	-199	241-510	-117.9	-11.8	-2.4	34.1
-0.59	-199	511-750	-70.2	-7.0	-1.4	22.1
-0.59	-199	751-1,000	-50.5	-5.1	-1.0	11.4
-0.59	-199	1,001-1,500	-35.4	-3.5	-0.7	8.2
-0.59	-199	1,501-2,000	-25.3	-2.5	-0.5	2.6
-0.59	-199	2,001-2,400	-20.1	-2.0	-0.4	1.0
-0.59	-199	2,401-3,000	-16.4	-1.6	-0.3	0.7
-0.59	-199	3,001 & Over	b			0.8

NOTES

Column:

1a	Line 7 (table 8) ÷ line 5 (table 7)
1b	Column 1a x line 4 (table 5) ÷ line 3 (table 5)
2	Breakdown corresponds to format of available data
3	Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a	Column 3 ÷ 10
4b	Column 3 ÷ 50
5	From billing frequency distributions for each sample utility

[a] Customer distributions for residential subclassification are based on LILCO's customer distribution for each subclass.

[b] Insufficient data to perform calculation.

Table 21. DOWNSTATE UTILITIES: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR AUTOMATIC METER-READING (INTERNATIONAL TELEDATA) ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer			Required Change in Peak Energy Consumption	Required Peak Period Elasticity Given a Peak Price Increase of		
kW	kWh	Consumption Size (kWh/month)	(%)	10%	50%	Total Customers in Class (%)[a]
-.09	-30	0-240	-55.6	-5.6	-1.1	19.1
-.09	-30	241-510	-17.8	-1.8	-0.4	34.1
-.09	-30	511-750	-10.6	-1.1	-0.2	22.1
-.09	-30	751-1,000	-7.6	-0.8	-0.2	11.4
-.09	-30	1,001-1,500	-5.3	-0.5	-0.1	8.2
-.09	-30	1,501-2,000	-3.8	-0.4	-0.1	2.6
-.09	-30	2,001-2,400	-3.0	-0.3	-0.1	1.0
-.09	-30	2,401-3,000	-2.5	-0.3	-0.1	0.7
-.09	-30	3,001 & Over	b			0.8

Table 22. DOWNSTATE UTILITIES: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR AUTOMATIC METER-READING (AMERICAN SCIENCE AND ENGINEERING) ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer			Required Change in Peak Energy Consumption	Required Peak Period Elasticity Given a Peak Price Increase of		
kW	kWh	Consumption Size (kWh/month)	(%)	10%	50%	Total Customers in Class (%)[a]
-0.23	78	0-240	-144.4	-14.4	-2.9	19.1
-0.23	78	241-510	-46.2	-4.6	-0.9	34.1
-0.23	78	511-750	-27.5	-2.8	-0.6	22.1
-0.23	78	751-1,000	-19.8	-2.0	-0.4	11.4
-0.23	78	1,001-1,500	-13.9	-1.4	-0.3	8.2
-0.23	78	1,501-2,000	-9.9	-1.0	-0.2	2.6
-0.23	78	2,001-2,400	-7.9	-0.9	-0.2	1.0
-0.23	78	2,401-3,000	-6.4	-0.6	-0.1	0.7
-0.23	78	3,001 & Over	b			0.8

NOTES

Column:

1a	Line 7 (table 8) ÷ line 5 (table 7)
1b	Column 1a x line 4 (table 5) ÷ line 3 (table 5)
2	Breakdown corresponds to format of available data
3	Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a	Column 3 ÷ 10
4b	Column 3 ÷ 50
5	From billing frequency distributions for each sample utility

[a] Customer distributions for residential subclassification are based on LILCO's customer distribution for each subclass.

[b] Insufficient data to perform calculation.

The calculations in table 20 show that, with the two-dial kWh meter with peak-demand capability, at a given peak-period price increase of 10 percent, only those customers with peak monthly consumption over 4,020 kWh could be cost-effectively metered. This represents less than 0.8 percent of customers. At a price increase of 50 percent, all customers over 1,001 kWh could be cost-effectively metered, or 13.3 percent of residential customers.

With the International Teledata automatic meter reading system (table 20), the necessary consumption cutoff point is 751 kWh per peak-period month, given a 10-percent peak-period price increase. This represents 24.7 percent of customers. With a 50-percent price increase, those customers who consume in excess of 241 kWh per peak month could be cost-effectively metered. This represents 80.9 percent of residential customers.

The American Science and Engineering automatic meter-reading system (table 22) requires a greater customer consumption for cost-effectiveness than the International Teledata system. Given a 10-percent peak-period price increase, 2,001 kWh (or 2.5 percent of the residential customers) is the breakpoint. At a greater price increase (50 percent), all customers who consume in excess of 241 kWh per peak month could be cost-effectively metered. This represents 80.9 percent of residential customers.

Section 6
CONCLUSIONS

The useful contribution made by this study is to offer a tool to utilities, public utility commissions, and other interested parties for investigating time-of-day pricing. It addresses the economic feasibility of adopting time-of-day pricing when existing electricity prices are constant and invariant with the time of day. It also provides a method of determining where the economies of time-of-day pricing lie.

With adequate information on customer responses, this method could be used to determine if residential customers (by kWh consumption size) have the ability to shift their electrical load in sufficient quantities to justify the expense of metering them for time-of-day consumption. In addition, with system-specific figures for incremental metering costs and incremental capacity investment, this method can be used to locate the reduction in kW per customer required to economically justify the implementation of time-of-day pricing for a particular utility system.

The reader should not be misled into thinking that the numerical exposition of our methodology provides a definitive assessment of time-of-day pricing for residential customers in New York State. Rather, we have attempted to illustrate an approach (with limitations) that can be followed.

Appendix A
DETAILED SUMMARY TABLES

Table A-1. INCREMENTAL CAPACITY INVESTMENT, 1978 $/kW

	Consolidated Edison	LILCO	Niagara Mohawk	Orange & Rockland	Rochester Gas & Electric
1. Generation, Installed	261[a]	181[b]	552[c]	195[d]	142[e]
2. Transmission and Distribution[f]	261	181	552	195	142
3. Subtotal[g]	522	362	1104	390	284
4. Reserves for Outages[h]	47	33	99	35	26
5. Incremental Capacity Investment[i]	569	395	1203	425	310

a. 1976 gas turbine figure of $230 x 1.1357, Marginal Cost Study, adjusted using Handy-Whitman Index July 1976-January 1978.
b. 1976 gas turbine figure of $159 x 1.1357, based on 1975 installations at Holbrook Plant, adjusted using Handy-Whitman Index.
c. Page 2, Schedule 5, of Marginal Cost Study; line 1 is an average of 10 additions planned for 1979-87 (1978 dollars).
d. Page 1, Schedule 8, Exhibit E-8 of Marginal Cost Study; figure represents cost of a gas turbine.
e. 1976 figure of $125 x 1.1357, value of contracted peaking capacity, marginal cost study, adjusted using July 1976-January 1978 Handy-Whitman Index.
f. Assumed equal to Line 1.
g. Line 1 + Line 2.
h. 18 percent of Line 1.
i. Lines 3 + 4.

Table A-2. ANNUAL CHARGE (PERCENTAGE)

	Consolidated Edison	LILCO	Niagara Mohawk	Orange & Rockland	Rochester Gas & Electric
1. Cost of Money[a]	8.91	9.83	9.44	9.35	9.31
2a. Depreciation, Capacity[b]	4.00	4.00	4.00	4.00	4.00
2b. Depreciation, Meters[c]	5.00	5.00	5.00	5.00	5.00
3. Taxes[d]	6.05	6.30	2.99	3.40	3.50
4. Insurance[e]	0.10	0.10	0.10	0.10	0.10
5a. Annual Capacity Charge[f]	19.06	20.23	16.53	16.85	16.91
5b. Annual Meter Charge[g]	14.01	14.93	14.54	14.45	14.41

[a] Most recent rate of return to rate base granted by the New York Public Service Commission.
[b] Straight-line depreciation, 25 years (NYDPS).
[c] Straight-line depreciation, 20 years (NYDPS).
[d] Taxes on real property (NYDPS). Consolidated Edison figure is average of 7.35 percent for production and 4.75 percent for transmission.
[e] Assumed equal to 1/10 of 1 percent (NYDPS).
[f] Lines 1 + 2a + 3 + 4.
[g] Lines 1 + 2b + 4 (taxes not on meters).

Table A-3. HOURS DURING PEAK PERIOD

	Consolidated Edison	LILCO	Niagara Mohawk	Orange & Rockland	Rochester Gas & Electric
1. Peak Hours/Day	14[a]	12[b]	14[c]	12[d]	16[e]
2. Peak Days/Week	5[a]	6[b]	5[c]	6[d]	5[e]
3. Peak Months/Year	5[a]	4[b]	5[c]	4[d]	7[e]
4. Total Peak Hours[f]	1516	1247	1516	1247	2425

[a] 8:00 a.m. - 10:00 p.m., Monday - Friday, May - September; Page 1, Exhibit ____ (LTM-1), Marginal Cost Study.

[b] 10:00 a.m. - 10:00 p.m., Monday - Saturday, June - September; Marginal Cost Study.

[c] 8:00 a.m. - 10:00 p.m., Monday - Friday, May - September; Marginal Cost Study.

[d] 10:00 a.m. - 10:00 p.m., Monday - Saturday, June - September; Page 17 Marginal Cost Study.

[e] 7:00 a.m. - 11:00 p.m., Monday - Friday, June - September and December - February.

[f] Line 1 x Line 2 x Line 3 x 4.33.

Table A-4. ANNUAL CUSTOMER SAVINGS IN RUNNING COSTS

Marginal Running Costs	Consolidated Edison	LILCO	Niagara Mohawk	Orange & Rockland	Rochester Gas & Electric
1. Peak Period (¢/kWh)	3.19[a]	3.76[b]	2.88[c]	2.49[d]	2.42[e]
2. Off-Peak Period (¢/kWh)	2.42[a]	2.64[b]	2.50[c]	2.25[d]	1.89[e]
3. Marginal Running Cost Premium (¢/kWh)[f]	0.77	1.12	0.38	0.24	0.53
4. Total Peak Hours[g]	1516	1247	1516	1247	2425
5. Marginal Running Cost Premium ($/kW)[h]	12	14	6	3	13

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[a] Page 2, Exhibit ____ (LTM-2) Marginal Cost Study; figures are an average of 1976-1980 because the difference (e.g., line 3) fluctuates.
[b] Exhibit ____ (RWB-9), Marginal Cost Study.
[c] Marginal Cost Study (NYDPS).
[d] Page 2, Schedule 8, Exhibit E-8, Marginal Cost Study.
[e] Marginal Cost Study (NYDPS).
[f] Line 1 - Line 2.
[g] Line 4, Table A-3.
[h] Line 3 x Line 4 ÷ 100.

Table A-5. ANNUALIZED BENEFITS OF TIME-OF-DAY PRICING, 1978 $kW

	Consolidated Edison	LILCO	Niagara Mohawk	Orange & Rockland	Rochester Gas & Electric
1. Incremental Capacity Invest. (1978 $/kW)[a]	569	395	1203	425	310
2. Annual Charge (%)[b]	19.06	20.23	16.53	16.85	16.91
3. Annualized Incremental Capacity Investment[c]	108	80	199	72	52
4. Annual Savings in Running Costs ($/kW)[d]	12	14	6	3	13
5. Total Annual Benefits (1978 $/kW)[e]	120	94	205	75	65

[a] Line 5, Table A-1.
[b] Line 5a, Table A-2.
[c] Line 1 x Line 2.
[d] Line 5, Table A-4.
[e] Lines 3 + 4.

Table A-6. ANNUALIZED INCREMENTAL COSTS FOR TIME-OF-DAY METERING (1978 $/METER)

	(1) Type 1	(2) Type 2	(3) Type 3	(4) Type 4[a]	(5) Type 4[b]	(6) Type 4[c]
	Meters			Automatic Meter Reading		
	Two-Dial kWh	Three-Dial kWh	Two-Dial kWh W/Peak kW	Int'l. Teledata	General Electric	American Science
Investment Costs						
1. Purchase[a]	130	145	240	36	197-242	167
2. Installation[b]	20	20	20	20[1]	N.A.	20[h]
3. Total initial Investment[c]	150	165	260	56	--	187
Incremental Annual Costs						
4. Maintenance[d]	10	12	15	1	N.A.	1
5. Reading & Processing[e]	3	3	4	--	N.A.	(6)
Annualized Investment Cost[f]						
6a. Consolidated Edison	21	23	36	8	--	26
6b. LILCO	22	25	39	8	--	28
6c. Orange & Rockland	22	24	38	8	--	27
6d. Niagara Mohawk	21	24	37	8	--	27
6e. Rochester Gas & Electric	21	23	37	8	--	27
Annualized Total Incremental[g]						
7a. Consolidated Edison	34	38	55	9	--	24
7b. LILCO	35	40	58	9	--	23
7c. Orange & Rockland	35	39	57	9	--	22
7d. Niagara Mohawk	34	39	56	9	--	22
7e. Rochester Gas & Electric	34	38	56	9	--	22

[a] Based on manufacturer's estimates.

[b] Assumes $20 installation costs for downstate utilities and $17 for upstate utilities to account for wage differentials.

[c] Line 1 + Line 2.

[d] Assumes annual maintenance cost of conventional meter equals zero. Based on a West Coast utility's estimates for time-of-day metering equipment.

[e] Costs for meter types 1, 2, and 3 are based on a West Coast utility's feasibility study of time-of-day metering options. Costs also include an estimated $2/per year for reprogramming costs. Type 4a costs are calculated as follows: $6.90 (estimate for existing meter reading and processing costs by a New York upstate utility), minus $0.75 (International Teledata's estimate for reading and processing costs per meter), minus an estimated $6.00 for annual telephone line leasing costs. Type 4c costs are calculated in the same way but do not include the annual line leasing costs.

[f] Lines 3 x Line 5b, Table 2.

[g] Lines 4 + 5 + 6.

[h] Installation of encoder at meter only. Software installation included in purchase costs.

Table A-7. ROCHESTER GAS AND ELECTRIC: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR TWO-DIAL kWh, ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%)[a]
kW	kWh			10%	50%	
-.52	-180	0-250	-261.8	-26.2	-5.2	21.8
-.52	-180	251-500	- 87.3	- 8.7	-1.7	30.5
-.52	-180	501-800	- 50.3	- 5.0	-1.0	23.4
-.52	-180	801-1,000	- 36.4	- 3.6	-0.7	7.3
-.52	-180	1,001-1,500	- 26.2	- 2.6	-0.5	6.7
-.52	-180	1,501-2,000	- 18.7	- 1.9	-0.4	1.9
-.52	-180	2,001 & Over	- 10.1	- 1.0	-0.2	1.8

NOTES:

Column

1a	Line 7 (table 6) ÷ line 5 (table 5)
1b	Column 1a x line 4 (table 3) ÷ line 3 (table 3)
2	Breakdown corresponds to format of available data
3	Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a	Column 3 ÷ 10
4b	Column 3 ÷ 50
5	From billing frequency distributions for each sample utility

[a] Customer distribution data not received from utility.

Table A-8. ROCHESTER GAS AND ELECTRIC: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR THREE-DIAL kWh, ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly	Required Change in Peak Energy Consumption	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class
kW	kWh	kWh)	(%)	10%	50%	Interval (%)[a]
-.58	-201	0-250	-292.4	-29.2	-5.8	21.8
-.58	-201	251-500	- 97.5	- 9.7	-1.9	30.5
-.58	-201	501-800	- 56.2	- 5.6	-1.1	23.4
-.58	-201	801-1,000	- 40.6	- 4.1	-0.8	7.3
-.58	-201	1,001-1,500	- 29.2	- 2.9	-0.6	6.7
-.58	-201	1,501-2,000	- 20.9	- 2.1	-0.4	1.9
-.58	-201	2,001 & Over	- 11.3	- 1.1	-0.2	1.8

NOTES:

Column

1a	Line 7 (table 6) ÷ line 5 (table 5)
1b	Column 1a x line 4 (table 3) ÷ line 3 (table 3)
2	Breakdown corresponds to format of available data
3	Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a	Column 3 ÷ 10
4b	Column 3 ÷ 50
5	From billing frequency distributions for each sample utility

[a] Customer distribution data not received from utility.

Table A-9. ROCHESTER GAS AND ELECTRIC: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR TWO-DIAL kWh - PEAK kW, ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%)[a]
kW	kWh			10%	50%	
-.86	-298	0-250	-433.5	-43.3	-8.7	21.8
-.86	-298	251-500	-144.5	-14.4	-2.9	30.5
-.86	-298	501-800	- 83.4	- 8.3	-1.7	23.4
-.86	-298	801-1,000	- 60.2	- 6.0	-1.2	7.3
-.86	-298	1,001-1,500	- 43.3	- 4.3	-0.9	6.7
-.86	-298	1,501-2,000	- 31.0	- 3.1	-0.6	1.9
-.86	-298	2,001 & Over	- 16.7	- 1.7	-0.3	1.8

NOTES:

Column

1a	Line 7 (table 6) ÷ line 5 (table 5)
1b	Column 1a x line 4 (table 3) ÷ line 3 (table 3)
2	Breakdown corresponds to format of available data
3	Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a	Column 3 ÷ 10
4b	Column 3 ÷ 50
5	From billing frequency distributions for each sample utility

[a] Customer distribution data not received from utility.

Table A-10. ROCHESTER GAS & ELECTRIC: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR AUTOMATIC METER READING (INTERNATIONAL TELEDATA), ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%) [a]
kW	kWh			10%	50%	
-.14	-49	0-250	-71.3	-7.1	-1.4	21.8
-.14	-49	251-500	-23.8	-2.4	-0.5	30.5
-.14	-49	501-800	-13.7	-1.4	-0.3	23.4
-.14	-49	801-1,000	- 9.9	-1.0	-0.2	7.3
-.14	-49	1,001-1,500	- 4.8	- .5	-0.1	6.7
-.14	-49	1,501-2,000	- 5.1	- .5	-0.1	1.9
-.14	-49	2,001 & Over	- 4.5	- .5	-0.1	1.8

NOTES:

Column

1a Line 7 (table 6) ÷ line 5 (table 5)
1b Column 1a x line 4 (table 3) ÷ line 3 (table 3)
2 Breakdown corresponds to format of available data
3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a Column 3 ÷ 10
4b Column 3 ÷ 50
5 From billing frequency distributions for each sample utility

[a] Customer distribution data not received from utility.

Table A-11. ROCHESTER GAS & ELECTRIC: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR AUTOMATIC METER READING (AMERICAN SCIENCE AND ENGINEERING), ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%)[a]
kW	kWh			10%	50%	
-.34	-118	0-250	-171.6	-17.2	-3.4	21.8
-.34	-118	251-500	- 57.2	- 5.7	-1.1	30.5
-.34	-118	501-800	- 33.0	- 3.3	-0.7	23.4
-.34	-118	801-1,000	- 23.8	- 2.4	-0.5	7.3
-.34	-118	1,001-1,500	- 11.6	- 1.2	-0.2	6.7
-.34	-118	1,501-2,000	- 12.3	- 1.2	-0.2	1.9
-.34	-118	2,001 & Over	- 10.7	- 1.1	-0.2	1.8

NOTES:

Column

1a Line 7 (table 6) ÷ line 5 (table 5)
1b Column 1a x line 4 (table 3) ÷ line 3 (table 3)
2 Breakdown corresponds to format of available data
3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a Column 3 ÷ 10
4b Column 3 ÷ 50
5 From billing frequency distributions for each sample utility

---

[a] Customer distribution data not received from utility.

Table A-12. CONSOLIDATED EDISON: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR TWO-DIAL kWh, ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%)[a]
kW	kWh			10%	50%	
-.28	-85	0-240	-157.4	-15.7	-3.1	
-.28	-85	241-510	- 50.4	- 5.0	-1.0	
-.28	-85	511-750	- 30.0	- 3.0	-0.6	
-.28	-85	751-1,000	- 21.6	- 2.2	-0.4	
-.28	-85	1,001-1,500	- 15.1	- 1.5	-0.3	
-.28	-85	1,501-2,000	- 10.8	- 1.1	-0.2	
-.28	-85	2,001-2,400	- 8.6	- 0.9	-0.2	
-.28	-85	2,401-3,000	- 7.0	- 0.7	-0.1	
-.28	-85	3,000 & Over	b			

NOTES:

<u>Column</u>

1a Line 7 (table 6) ÷ line 5 (table 5)
1b Column 1a x line 4 (table 3) ÷ line 3 (table 3)
2 Breakdown corresponds to format of available data
3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a Column 3 ÷ 10
4b Column 3 ÷ 50
5 From billing frequency distributions for each sample utility

---

[a] Customer distribution data not received from utility.
[b] Insufficient data to perform calculation.

Table A-13. CONSOLIDATED EDISON: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR THREE-DIAL kWh, ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%)[a]
kW	kWh			10%	50%	
-.32	-97	0-240	-179.6	-18.0	-3.6	
-.32	-97	241-510	- 57.5	- 5.7	-1.1	
-.32	-97	511-750	- 34.2	- 3.4	-0.7	
-.32	-97	751-1,000	- 24.6	- 2.5	-0.5	
-.32	-97	1,001-1,500	- 17.2	- 1.7	-0.3	
-.32	-97	1,501-2,000	- 12.3	- 1.2	-0.2	
-.32	-97	2,001-2,400	- 9.8	- 1.0	-0.2	
-.32	-97	2,401-3,000	- 8.0	- 0.8	-0.2	
-.32	-97	3,000 & Over	b			

NOTES:

Column

- 1a Line 7 (table 6) ÷ line 5 (table 5)
- 1b Column 1a x line 4 (table 3) ÷ line 3 (table 3)
- 2 Breakdown corresponds to format of available data
- 3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
- 4a Column 3 ÷ 10
- 4b Column 3 ÷ 50
- 5 From billing frequency distributions for each sample utility

---

[a] Customer distribution data not received from utility.
[b] Insufficient data to perform calculation.

Table A-14. CONSOLIDATED EDISON: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR TWO-DIAL kWh - PEAK kW, ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%)[a]
kW	kWh			10%	50%	
-.46	-139	0-240	-257.4	-25.7	-5.1	
-.46	-139	241-510	- 82.4	- 8.2	-1.6	
-.46	-139	511-750	- 49.0	- 4.9	-1.0	
-.46	-139	751-1,000	- 35.3	- 3.5	-0.7	
-.46	-139	1,001-1,500	- 24.7	- 2.5	-0.5	
-.46	-139	1,501-2,000	- 17.7	- 1.8	-0.4	
-.46	-139	2,001-2,400	- 14.0	- 1.4	-0.3	
-.46	-139	2,401-3,000	- 11.4	- 1.1	-0.2	
-.46	-139	3,000 & Over	b			

NOTES:

Column

1a Line 7 (table 6) ÷ line 5 (table 5)
1b Column 1a x line 4 (table 3) ÷ line 3 (table 3)
2 Breakdown corresponds to format of available data
3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a Column 3 ÷ 10
4b Column 3 ÷ 50
5 From billing frequency distributions for each sample utility

---

[a] Customer distribution data not received from utility.
[b] Insufficient data to perform calculation.

Table A-15. CONSOLIDATED EDISON: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR AUTOMATIC METER READING (INTERNATIONAL TELEDATA), ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%)[a]
kW	kWh			10%	50%	
-.08	-24	0-240	-44.4	-4.4	-0.9	
-.08	-24	241-510	-14.2	-1.4	-0.3	
-.08	-24	511-750	- 8.5	-0.9	-0.2	
-.08	-24	751-1,000	- 6.1	-0.6	-0.1	
-.08	-24	1,001-1,500	- 4.3	-0.4	-0.1	
-.08	-24	1,501-2,000	- 3.1	-0.3	-0.1	
-.08	-24	2,001-2,400	- 2.4	-0.2	-0.0	
-.08	-24	2,401-3,000	- 2.0	-0.2	-0.0	
-.08	-24	3,000 & Over	b			

NOTES:

Column

1a Line 7 (table 6) ÷ line 5 (table 5)
1b Column 1a x line 4 (table 3) ÷ line 3 (table 3)
2 Breakdown corresponds to format of available data
3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a Column 3 ÷ 10
4b Column 3 ÷ 50
5 From billing frequency distributions for each sample utility

[a] Customer distribution data not received from utility.
[b] Insufficient data to perform calculation.

Table A-16. CONSOLIDATED EDISON: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR AUTOMATIC METER READING (AMERICAN SCIENCE AND ENGINEERING), ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%)[a]
kW	kWh			10%	50%	
-0.20	-61	0-240	-113.0	-11.3	-2.3	
-0.20	-61	241-510	- 36.2	- 3.6	-0.7	
-0.20	-61	511-750	- 21.5	- 2.2	-0.4	
-0.20	-61	751-1,000	- 13.9	- 1.4	-0.3	
-0.20	-61	1,001-1,500	- 10.8	- 1.1	-0.2	
-0.20	-61	1,501-2,000	- 7.8	- 0.8	-0.2	
-0.20	-61	2,001-2,400	- 6.2	- 0.6	-0.1	
-0.20	-61	2,401-3,000	- 5.0	- 0.5	-0.1	
-0.20	-61	3,000 & Over	b			

NOTES:

Column

- 1a Line 7 (table 6) ÷ line 5 (table 5)
- 1b Column 1a x line 4 (table 3) ÷ line 3 (table 3)
- 2 Breakdown corresponds to format of available data
- 3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
- 4a Column 3 ÷ 10
- 4b Column 3 ÷ 50
- 5 From billing frequency distributions for each sample utility

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[a] Customer distribution data not received from utility.
[b] Insufficient data to perform calculation.

Table A-17. LONG ISLAND LIGHTING CO.: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR TWO-DIAL kWh, ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%)[a]
kW	kWh			10%	50%	
-.37	-115	0-240	-213.0	-21.3	-4.3	19.1
-.37	-115	241-510	- 68.1	- 6.8	-1.4	34.1
-.37	-115	511-750	- 40.6	- 4.1	-0.8	22.1
-.37	-115	751-1,000	- 29.2	- 2.9	-0.6	11.4
-.37	-115	1,001-1,500	- 20.4	- 2.0	-0.4	8.2
-.37	-115	1,501-2,000	- 14.6	- 1.5	-0.3	2.6
-.37	-115	2,001-2,400	- 11.6	- 1.2	-0.2	1.0
-.37	-115	2,401-3,000	- 9.5	- 0.9	-0.2	0.7
-.37	-115	3,000 & Over	- 3.7	- 0.4	-0.1	0.8

NOTES:

Column

1a Line 7 (table 6) ÷ line 5 (table 5)
1b Column 1a x line 4 (table 3) ÷ line 3 (table 3)
2 Breakdown corresponds to format of available data
3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a Column 3 ÷ 10
4b Column 3 ÷ 50
5 From billing frequency distributions for each sample utility

[a] Customer distribution data not received from utility.

Table A-18. LONG ISLAND LIGHTING CO.: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR THREE-DIAL kWh, ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%)[a]
kW	kWh			10%	50%	
-.43	-134	0-240	-248.1	-24.8	-5.0	19.1
-.43	-134	241-510	- 79.4	- 7.9	-1.6	34.1
-.43	-134	511-750	- 47.3	- 4.7	-0.9	22.1
-.43	-134	751-1,000	- 34.0	- 3.4	-0.7	11.4
-.43	-134	1,001-1,500	- 23.8	- 2.4	-0.5	8.2
-.43	-134	1,501-2,000	- 17.0	- 1.7	-0.3	2.6
-.43	-134	2,001-2,400	- 13.5	- 1.4	-0.3	1.0
-.43	-134	2,401-3,000	- 11.0	- 1.1	-0.2	0.7
-.43	-134	3,000 & Over	- 4.3	- 0.4	-0.1	0.8

NOTES:

Column

1a Line 7 (table 6) ÷ line 5 (table 5)
1b Column 1a x line 4 (table 3) ÷ line 3 (table 3)
2 Breakdown corresponds to format of available data
3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a Column 3 ÷ 10
4b Column 3 ÷ 50
5 From billing frequency distributions for each sample utility

[a] Customer distribution data not received from utility.

Table A-19. LONG ISLAND LIGHTING CO.: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR TWO-DIAL kWh - PEAK kW, ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%)[a]
kW	kWh			10%	50%	
-.62	-193	0-240	-357.4	-35.7	-7.1	19.1
-.62	-193	241-510	-144.4	-11.4	-2.3	34.1
-.62	-193	511-750	- 68.1	- 6.8	-1.4	22.1
-.62	-193	751-1,000	- 49.0	- 4.9	-1.0	11.4
-.62	-193	1,001-1,500	- 34.3	- 3.4	-0.7	8.2
-.62	-193	1,501-2,000	- 24.5	- 2.5	-0.5	2.6
-.62	-193	2,001-2,400	- 19.5	- 1.9	-0.4	1.0
-.62	-193	2,401-3,000	- 15.9	- 1.6	-0.3	0.7
-.62	-193	3,000 & Over	- 6.1	- 0.6	-0.1	0.8

NOTES:

Column

1a Line 7 (table 6) ÷ line 5 (table 5)
1b Column la x line 4 (table 3) ÷ line 3 (table 3)
2 Breakdown corresponds to format of available data
3 Column lb ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a Column 3 ÷ 10
4b Column 3 ÷ 50
5 From billing frequency distributions for each sample utility

[a] Customer distribution data not received from utility.

Table A-20. LONG ISLAND LIGHTING CO.: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR AUTOMATIC METER READING (INTERNATIONAL TELEDATA), ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%) [a]
kW	kWh			10%	50%	
-.10	-31	0-240	-57.4	-5.7	-1.1	19.1
-.10	-31	241-510	-18.4	-1.8	-0.4	34.1
-.10	-31	511-750	-10.9	-1.1	-0.2	22.1
-.10	-31	751-1,000	- 7.9	-0.8	-0.2	11.4
-.10	-31	1,001-1,500	- 5.5	-0.6	-0.1	8.2
-.10	-31	1,501-2,000	- 3.9	-0.4	-0.1	2.6
-.10	-31	2,001-2,400	- 3.1	-0.3	-0.1	1.0
-.10	-31	2,401-3,000	- 2.6	-0.3	-0.1	0.7
-.10	-31	3,000 & Over	- 2.2	-0.2	0.0	0.8

NOTES:

Column

1a Line 7 (table 6) ÷ line 5 (table 5)
1b Column 1a x line 4 (table 3) ÷ line 3 (table 3)
2 Breakdown corresponds to format of available data
3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a Column 3 ÷ 10
4b Column 3 ÷ 50
5 From billing frequency distributions for each sample utility

[a] Customer distribution data not received from utility.

Table A-21. LONG ISLAND LIGHTING CO.: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR AUTOMATIC METER READING (AMERICAN SCIENCE AND ENGINEERING), ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%) [a]
kW	kWh			10%	50%	
-.24	-75	0-240	-138.9	-13.9	-2.8	19.1
-.24	-75	241-510	- 44.4	- 4.4	-0.9	34.1
-.24	-75	511-750	- 26.5	- 2.7	-0.5	22.1
-.24	-75	751-1,000	- 19.1	- 1.9	-0.4	11.4
-.24	-75	1,001-1,500	- 13.3	- 1.3	-0.3	8.2
-.24	-75	1,501-2,000	- 9.5	- 1.0	-0.2	2.6
-.24	-75	2,001-2,400	- 7.6	- 0.9	-0.2	1.0
-.24	-75	2,401-3,000	- 6.2	- 0.6	-0.1	0.7
-.24	-75	3,000 & Over	- 5.3	- 0.5	-0.1	0.8

NOTES:

Column

- 1a Line 7 (table 6) ÷ line 5 (table 5)
- 1b Column 1a x line 4 (table 3) ÷ line 3 (table 3)
- 2 Breakdown corresponds to format of available data
- 3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
- 4a Column 3 ÷ 10
- 4b Column 3 ÷ 50
- 5 From billing frequency distributions for each sample utility

[a] Customer distribution data not received from utility.

Table A-22. ORANGE AND ROCKLAND: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR TWO-DIAL kWh, ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%)[a]
kW	kWh			10%	50%	
-.47	-147	0-240	-272.2	-27.2	-5.4	
-.47	-147	241-510	- 87.1	- 8.7	-1.7	
-.47	-147	511-750	- 51.9	- 5.2	-1.0	
-.47	-147	751-1,000	- 37.3	- 3.7	-0.7	
-.47	-147	1,001-1,500	- 26.1	- 2.6	-0.5	
-.47	-147	1,501-2,000	- 18.7	- 1.9	-0.4	
-.47	-147	2,001-2,400	- 14.8	- 1.5	-0.3	
-.47	-147	2,401-3,000	- 12.1	- 1.2	-0.2	
-.47	-147	3,000 & Over	b			

NOTES:

Column

1a Line 7 (table 6) ÷ line 5 (table 5)
1b Column 1a x line 4 (table 3) ÷ line 3 (table 3)
2 Breakdown corresponds to format of available data
3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a Column 3 ÷ 10
4b Column 3 ÷ 50
5 From billing frequency distributions for each sample utility

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[a] Customer distribution data not received from utility.
[b] Insufficient data to perform calculation.

Table A-23. ORANGE AND ROCKLAND: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR THREE-DIAL kWh, ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%) [a]
kW	kWh			10%	50%	
-.52	-162	0-240	-300.0	-30.0	-6.0	
-.52	-162	241-510	- 96.0	- 9.6	-1.9	
-.52	-162	511-750	- 57.1	- 5.7	-1.1	
-.52	-162	751-1,000	- 41.1	- 4.1	-0.8	
-.52	-162	1,001-1,500	- 28.8	- 2.8	-0.6	
-.52	-162	1,501-2,000	- 20.6	- 2.1	-0.4	
-.52	-162	2,001-2,400	- 16.3	- 1.6	-0.3	
-.52	-162	2,401-3,000	- 13.3	- 1.3	-0.3	
-.52	-162	3,000 & Over	b			

NOTES:

Column

1a Line 7 (table 6) ÷ line 5 (table 5)
1b Column 1a x line 4 (table 3) ÷ line 3 (table 3)
2 Breakdown corresponds to format of available data
3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a Column 3 ÷ 10
4b Column 3 ÷ 50
5 From billing frequency distributions for each sample utility

---

[a] Customer distribution data not received from utility.
[b] Insufficient data to perform calculation.

Table A-24. ORANGE AND ROCKLAND: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR TWO-DIAL kWh - PEAK kW, ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%)[a]
kW	kWh			10%	50%	
-.76	-237	0-240	-438.9	-43.9	-8.8	
-.76	-237	241-510	-140.4	-14.0	-2.8	
-.76	-237	511-750	- 83.6	- 8.4	-1.7	
-.76	-237	751-1,000	- 60.2	- 6.0	-1.2	
-.76	-237	1,001-1,500	- 42.1	- 4.2	-0.8	
-.76	-237	1,501-2,000	- 30.1	- 3.0	-0.6	
-.76	-237	2,001-2,400	- 23.9	- 2.4	-0.5	
-.76	-237	2,401-3,000	- 19.5	- 1.9	-0.4	
-.76	-237	3,000 & Over	b			

NOTES:

Column

1a Line 7 (table 6) ÷ line 5 (table 5)
1b Column 1a x line 4 (table 3) ÷ line 3 (table 3)
2 Breakdown corresponds to format of available data
3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a Column 3 ÷ 10
4b Column 3 ÷ 50
5 From billing frequency distributions for each sample utility

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[a] Customer distribution data not received from utility.
[b] Insufficient data to perform calculation.

Table A-25. ORANGE AND ROCKLAND: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR AUTOMATIC METER READING (INTERNATIONAL TELEDATA), ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%)[a]
kW	kWh			10%	50%	
-.12	-37	0-240	-68.5	-6.9	-1.4	
-.12	-37	241-510	-21.9	-2.2	-0.4	
-.12	-37	511-750	-13.1	-1.3	-0.3	
-.12	-37	751-1,000	- 9.4	-0.9	-0.2	
-.12	-37	1,001-1,500	- 6.6	-0.7	-0.1	
-.12	-37	1,501-2,000	- 4.7	-0.5	-0.1	
-.12	-37	2,001-2,400	- 3.7	-0.4	-0.1	
-.12	-37	2,401-3,000	- 3.1	-0.3	-0.1	
-.12	-37	3,000 & Over	b			

NOTES:

Column

1a Line 7 (table 6) ÷ line 5 (table 5)
1b Column 1a x line 4 (table 3) ÷ line 3 (table 3)
2 Breakdown corresponds to format of available data
3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
4a Column 3 ÷ 10
4b Column 3 ÷ 50
5 From billing frequency distributions for each sample utility

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[a] Customer distribution data not received from utility.
[b] Insufficient data to perform calculation.

Table A-26. ORANGE AND ROCKLAND: REQUIRED ELASTICITY BY CUSTOMER SIZE FOR AUTOMATIC METER READING (AMERICAN SCIENCE AND ENGINEERING), ASSUMING A PERCENTAGE INCREASE IN THE PRICE OF PEAK-PERIOD ENERGY

(1a)	(1b)	(2)	(3)	(4a)	(4b)	(5)
Required Change Per Customer		Consumption Size (Monthly kWh)	Required Change in Peak Energy Consumption (%)	Required Peak Period Elasticity Given a Peak Price Increase of		Residential Customers by Consumption Class Interval (%)[a]
kW	kWh			10%	50%	
-0.29	-91	0-240	-168.5	-16.9	-3.4	
-0.29	-91	241-510	- 53.9	- 5.4	-1.1	
-0.29	-91	511-750	- 32.1	- 3.2	-0.6	
-0.29	-91	751-1,000	- 23.1	- 2.3	-0.5	
-0.29	-91	1,001-1,500	- 16.2	- 1.6	-0.3	
-0.29	-91	1,501-2,000	- 11.6	- 1.2	-0.2	
-0.29	-91	2,001-2,400	- 9.2	- 0.9	-0.2	
-0.29	-91	2,401-3,000	- 7.5	- 0.8	-0.2	
-0.29	-91	3,000 & Over	b			

NOTES:

Column

- 1a Line 7 (table 6) ÷ line 5 (table 5)
- 1b Column 1a x line 4 (table 3) ÷ line 3 (table 3)
- 2 Breakdown corresponds to format of available data
- 3 Column 1b ÷ midpoint of column 2 ÷ f, where f = 0.55 for upstate utilities and 0.45 for downstate utilities
- 4a Column 3 ÷ 10
- 4b Column 3 ÷ 50
- 5 From billing frequency distributions for each sample utility

[a] Customer distribution data not received from utility.
[b] Insufficient data to perform calculation.

Table A-27. UPSTATE UTILITIES: REQUIRED kWh CONSUMPTION AND PERCENT OF CUSTOMERS COST-EFFECTIVELY METERED

		Consumption, Given Price Increases			
		10 percent increase		50 Percent Increase	
	Rate Classification	kWh	Percent of Total Customers	kWh	Percent of Total Customers
Upstate	Total Residential				
2 dial kWh meter		2,000	1.4	500	37.9
3 dial kWh meter		2,000	1.4	500	37.9
2 dial kWh with on-peak kW		4,181[a]	-	800	16.1
Automatic meter reading					
International Teledata		800	16.1	250	69.8
American Science and Engineering		1,500	3.0	250	69.8
Rochester Gas and Electric	Total Residential				
2 dial kWh meter		2,000	1.8	500	47.7
3 dial kWh meter		2,000	1.8	500	47.7
2 dial kWh with on-peak kW		2,000	1.8	800	17.7
Automatic Meter Reading					
International Teledata		800	17.7	250	71.6
American Science and Engineering		1,000	10.40	250	71.6

[a] Actual kWh consumption size breakpoint; therefore, less than 1.4 percent of customers could be cost-effectively metered.

Table A-28. DOWNSTATE UTILITIES: REQUIRED kWh CONSUMPTION AND PERCENT OF CUSTOMERS COST-EFFECTIVELY METERED

	Rate Classification	Consumption, Given Price Increases: 10 Percent Increase: kWh	10 Percent Increase: Percent of Total Customers	50 Percent Increase: kWh	50 Percent Increase: Percent of Total Customers
Downstate	Residential				
2 dial kWh meter	General	2,000	2.4	511	46.3
3 dial kWh meters		2,401	1.5	511	46.3
2 dial kWh meter with on-peak kW		2,783[a]	-	751	24.2
Automatic meter reading					
International Teledata		511	46.3	ALL	100.0
American Science and Engineering		1,501	5.0	241	80.6
2 dial kWh meter	Residential	2,000	2.6	511	55.3
3 dial kWh meter	with water	2,401	1.5	511	55.3
2 dial kWh meter with on-peak kW		2,783[a]	-	751	33.2
Automatic meter reading		751	33.2	241	84.8
Consolidated Edison					
2 dial kWh meter		1,501	-	241	-
3 dial kWh meter		1,501	-	241	-
2 dial kWh meter with on-peak kW		2,401	-	511	-
Automatic meter reading					
International Teledata		511	-	ALL	100.0
American Science and Engineering		1,000	-	240	-
Long Island Lighting	Residential				
2 dial kWh meter	General	2,001	5.0	511	46.3
3 dial kWh meter		2,401	4.1	511	46.3
2 dial kWh meter with on-peak kW		3,299[a]	-	751	24.2
Automatic meter reading					
International Teledata		511	46.3	ALL	100.0
American Science and Engineering		1,000	13.0	240	80.60
2 dial kWh meter	Residential	2,001	2.6	511	55.3
3 dial kWh meter	General and	2,401	1.5	511	55.3
2 dial kWh meter with on-peak kW	Water Heating	3,299[a]	-	751	33.2

Table A-28. cont'd

Rate Classification	Consumption, Given Price Increases: 10 Percent Increase — kWh	10 Percent Increase — Percent of Total Customers	50 Percent Increase — kWh	50 Percent Increase — Percent of Total Customers
Automatic meter reading				
International Teledata	511	46.3	ALL	100.0
American Science and Engineering	1,000	18.2	240	84.8
Orange and Rockland				
2 dial kWh meter	2,401	-	511	-
3 dial kWh meter	2,401	-	511	-
2 dial kWh meter with on-peak kW	4,051[a]	-	751	-
Automatic meter reading				
International Teledata	511	-	240	-
American Science and Engineering	1,500	-	240	-

[a] Actual kWh consumption breakpoint; therefore, less than 0.8 percent of customers could be cost-effectively metered.

Table A-29. TOTAL ENERGY CONSUMED DURING PEAK HOURS AS A PERCENT OF TOTAL ENERGY CONSUMED IN PEAK MONTHS

Customer Size (kWh)	Regular General Customers[a]	Time-of-Day General Customers[b]
Orange and Rockland		
0 - 130	43%	48%
131 - 300	49	45
301 - 500	48	42
501 - 1,000	54	44
1,001 - 1,500	51	49
1,501+	54	49
Average	50	46
		General and Space Heating
Consolidated Edison[c]		
Average	39	53
Rochester Gas and Electric		
Average	60	51

NOTE: Breakdown by customer size not available for Consolidated Edison, LILCO, and Rochester Gas and Electric.

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[a] From July 1977 (peak month) load data.
[b] From time-of-day pricing experiment (based on peak month of July).
[c] Figures should be interpreted as approximate and pertain to peak months.