REGIONAL VARIATION IN ELECTRIC ENERGY: DEMAND RESPONSIVENESS IN THE RESIDENTIAL SECTOR IN ILLINOIS

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Introduction

The large number of recently published econometric studies of electricity demand[1] reflects the present national concern with energy problems. Some of the primary goals of current research on electricity demand have been to resolve issues related to (1) the appropriate specification of the price for electricity that is sold at declining marginal rates; (2) the importance of the aggregation bias that is produced by using state or national data series: (3) the nature and extent of regional differences in electricity demand responsiveness. Of these three, the last issue has received the least amount of attention particularly with respect to analysis of smaller-than-state regions.

Although several studies have shown that differences in electricity demand functions exist for regions composed of states grouped according to geographic proximity [1, 6, 17, 24], degree of urbanization [14], and weather conditions [5], only the studies by Fisher and Kaysen [6] and Lyman [17] showed that these regional differences were statistically significant. Fisher and Kaysen further applied analysis of covariance to identify groups of states that were homogeneous with respect to their demand function characteristics. Based on the composition of these groups, Fisher and Kaysen were able to suggest that demand function differences among homogeneous regions were due to differences in degree of urbanization and size and type of appliance stocks.

This paper has two main goals:

(1) To examine the extent of regional differences in residential electricity demand responsiveness among utility company service areas and service area subdivisions within Illinois (Figure 1).
(2) To investigate, for smaller-than-state regions, the econometric implications of price variables for residential electricity demand that are computed from actual rate schedules.

With respect to the first goal, it is hypothesized that the diverse economic and climatic conditions within Illinois are likely to produce diverse residential electricity consumption patterns. Northern Illinois is more urbanized, more

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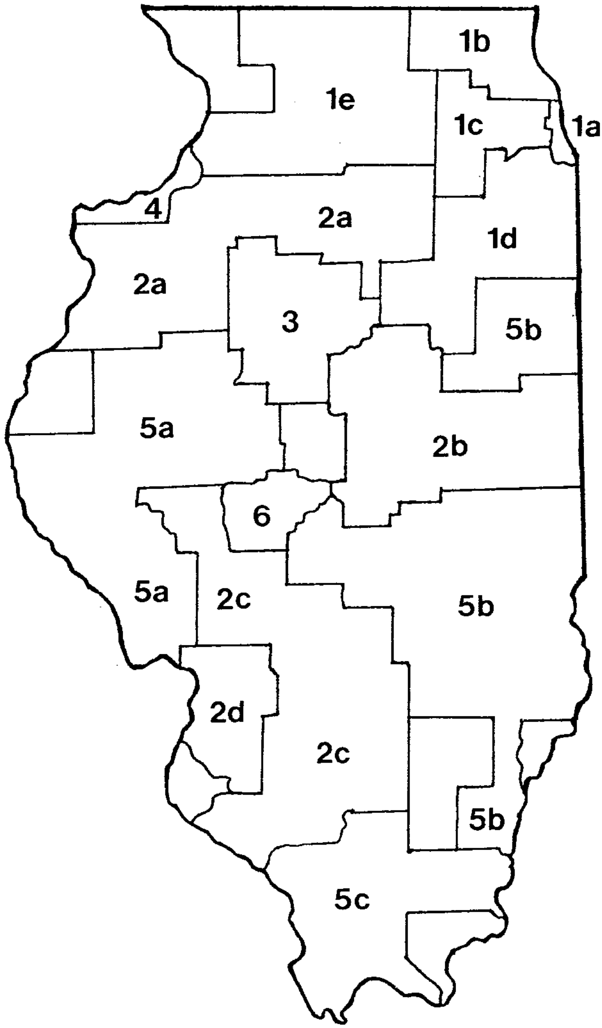
[1] Publications by Taylor [20, 21], Mitchel [18], and Hoffman and Wood [11] contain reviews of most of the relevant econometric studies of electricity demand completed through 1976. Important additions to this voluminous literature include studies by Chern and Just [1], Chern et. al. [2], Cicchetti and Smith [3], Crist [4], Gill and Madala [7], Griffin [8], Halvorsen [9, 10], Houthakker [12], Taylor, Blattenberger, and Verleger [22], U.S. Federal Energy Administration [24], Uri [28], and Wilder and Willenborg [30].

FIGURE 1
Major Utility Company Service Areas and Service Area Subdivisions in Illinois.



industrialized, more affluent, and, of course, colder than southern Illinois. Northern Illinois contains the densely populated Chicago metropolitan area and several other large cities, while southern Illinois is predominantly rural.

Given these intrastate differences, residential electricity demand functions were estimated for utility company service areas and company-designated service area subdivisions in order to maximize the potential for analyzing regional variation in electricity demand data that are publicly available. The problems of supressing regional variation and aggregation bias are well known [22, p. 9-1]. Estimates of electricity demand functions for areas such as entire states necessarily capture an "averaged" responsiveness of what is occurring within individual utility service areas.

Modeling Framework

Following Taylor, Blattenberger and Verleger [22], this research postulates that the consumption of electricity is a function of the entire rate schedule from which it is purchased. In addition, if electricity is being priced in blocks having decreasing marginal prices the implication is that consumers alter their purchases of electricity in response to changes in two types of prices: margional price and intramarginal price. Marginal price is the price per kilowatt-hour (kwh) attached to the last consumption block chosen by the consumer, while intramarginal price is the extra cost that a consumer who faces a decreasing block rate structure pays in order to consume at the desired marginal rate. Increases in this price give rise solely to income effects, unless the change is sufficiently large to drive the consumer onto a block having a higher marginal price.

Most existing econometric studies of residential electricity demand use average prices that are calcuated ex post from data on revenues and kwh consumption, or that are taken from *Typical Electric Bills* [27]. Ex post average prices create simultaneity problems: price and consumption are determined together. The *Typical Electric Bill* data only approximate actual rate schedules and have associated aggregation problems.

Because electricity is regarded as a commodity that is consumed in conjunction with electricity-using durable goods, the demand for electricity is generally characterized in dynamic terms. A distinction is made between short run and long run mechanisms for changing electricity demand. In the short run, the sizes and technical characteristics of appliance stocks are viewed as being fixed, and hence, electricity consumption depends on the utilization rates of these existing stocks. In the long run, consumers may change their stocks of appliances, making the long run demand for electricity equivalent to the long run desired demand for electrical appliances.

Two classes of demand models have been used to represent these kinds of dynamic relationships for electricity. In the first class, or flow adjustment models, the stock of appliances is represented implicitly [13, 14]. In the second class, or stock adjustment models, capital stock variables are included as explicit arguments [20, 22].[2] Because of the difficulty of assembling a complete and consistent data set for appliance stocks in the smaller-than-state regions being analyzed, flow adjustment demand functions incorporating the familiar Koyck geometric distributed lag were estimated for this study.

Specifically, in a manner similar to Taylor, Blattenberger, and Verleger [22], residential electricity demand is viewed as following a simple price determined, flow adjustment model in which the desired demand for electricity (q^*_{it}) by residential customers in region i at time t is a function of marginal price (p), intramarginal price (c), gass price (g), and personal income (y).

[2] Time-series appliance stock data are not available for the geographic areas being analyzed here.

$$(1) \qquad q^* = f(P_{it}, c_{it}, g_{it}, y_{it})$$

The adjustment between actual demand (q_{it}) and desired demand is assumed to take place in a discrete manner according to the following multiplicative adjustment with $0 < \theta < 1$,[3]

$$(2) \qquad (q_{it}/q_{i,t-1}) = (q^*_{it}/q_{i,t-1})^{\theta}$$

Assuming that the desired demand function (1) is multiplicative,

$$(3) \qquad q^*_{it} = \beta_0 \circ p_{it}^{\beta_1} \circ c_{it}^{\beta_2} \circ g_{it}^{\beta_3} \circ y_{it}^{\beta_4}$$

inserting equation (3) into equation (2) and taking the logarithms of the result produces the following log-linear estimating equation for residential electricity demand.

$$(4) \qquad \ln q_{it} = \theta \ln \beta_0 \cdot \theta\beta_1 \ln p_{it} + \theta\beta_2 \ln c_{it} + \theta\beta_3 \ln g_{it} + \theta\beta_4 \ln y_{it} + (1-\theta) \ln q_{i,t-1}$$

For this kind of function, long run elasticities are proportionate to short run elasticities and the percent of total elasticity responsiveness that occurs in each period is a geometric junction of the coefficient of the lagged dependent variable.

Estimation Procedures and Data

In this analysis, the state of Illinois is viewed as being made up of a cross-section of 15 regions where three of the regions represent complete utility company service areas and the remaning 12 regions are service area subdivisions of the larger utilities. A time-series of observations on the variables is collected for each of these regions. Residential electricity demand functions for the regions are estimated from the time-series data, while pooling of the cross-section and time-series observations permits the estimation of demand junctions for the entire state and the utilities with service area subdivisions.

Because a lagged dependent variable is present in the model being estimated, the individual disturbance terms are assumed to follow a first order autoregressive scheme. As is well known, in this estimation situation ordinary least squares estimators are inconsistent. To obtain consistent estimates of the coefficients in equation (4), the two-round instrumental variable estimator proposed by Wallis [29] was used. The Wallis procedure was selected primarily for reasons of practicability. Although other procedures, like maximum likelihood estimation or iteration and search techniques, may also produce consistent estimates, these procedures often require the solution of large systems of nonlinear equations or the use of expensive computational means.

Using personal income as the instrumental variable, the first round of the Wallis procedure produces a first order serial correlation coefficient. In the second round, this serial correlation coefficient is employed in the generalized

[3] The discrete time specification was judged to be the preferred specification by Taylor, Blattenberger, and Verleger [22, p. 5-12].

least squares estimator to obtain estimates of the demand function coefficients for each region. For the state and larger utility company demand functions using the pooled data, the estimation procedure is basically the same as the Wallis procedure except for the addition of a third round of estimation. This third round of estimation employs the procedure described by Kmenta [16] and is needed to adjust for the heteroskedasticity present in the pooled samples.

Estimates of the parameters of residential electricity demand functions were made using annual time-series data for a cross-section of 15 utility service areas and service area subdivisions for the period 1960 to 1976. The boundaries for these regions were determined from utility maps [26], and except for the City of Chicago, county boundaries were used to approximate service area and subdivision boundaries. Counties that were served by more than one utility company were assigned to the utility company that serves the highest percentage of the population. Table 1 presents the variable specifications and data sources that were used.

The electric price observations were based on the rate schedules from which the utilities computed bills for a majority of their residential customers. These schedules were used to obtain estimates of both intramarginal price (IP) and marginal price (MP) variables. A typical black defined as the block in which mean monthly consumption per customer occurred is used to calculate the price observations. Given that the typical block is known to be the n^{th} block,

$$\text{(5)} \qquad IP = CC + \sum_{i=1}^{n-1} ((RATE_i - RATE_n) \cdot KWH_i)$$

and

$$\text{(6)} \qquad MP = RATE_n + F$$

where:

CC = customer charge.
F = fuel adjustment in cents per kwh.
KWH_i = number of kwh in the i^{th} block.
$RATE_i$ = cents per kwh price in the i^{th} block.

Since rate schedules change on an irregular basis, calendar year data were determined by weighting each schedule according to the number of days it was in effect during a given year. If the block demarcations were different, then the union of all block demarcations effective during the year of change was used. Monthly increases in rates due to fuel adjustment charges were approximated by linear interpolations from published spot values [25].

Empirical Results

Residential demand functions for individual utility companies and for the entire state are presented in Table 2. Before examining regional variations among the demand functions it is important to consider the general character of the results. The results are encouraging with respect to the performance of personal income and marginal price as explanatory variables, but they indi-

TABLE 1. Variable Specifications and Data Sources.

Variable Specifications	Source
Quantity Demanded Kilowatt-hours per capita[a]	U.S. Federal Energy Regulatory Commission [26].
Electricity Price[b] Intramarginal Price (1967 dollars)[c] Marginal Price (1967 dollars/kwh)	U.S. Federal Energy Regulatory Commission [25].
Personal Income[d] (1976 dollars per capita)	U.S. Bureau of Economic Analysis [23].
Natural Gas Price (1967 dollars per thousand cubic feet)	Illinois Commerce Commission [19].

[a]Per capita sales were calculated using county population estimates published by U.S. Bureau of Economic Analysis [23].

[b]See text for discussion of procedures used to compute the price variables.

[c]Regional Consumer Price Indexes (Chicago or St. Louis) were used as deflators.

[d]County per capita personal income data were estimated for the missing years, 1960, 1961, 1963, and 1964 using the following interpolation procedure:

$$Y_{i,m}=[[(s_{i,k})(t-k)+(s_{i,t}-s_{i,k})(m-k)]/(t-k)]\cdot y_m$$

where:

$y_{i,m}$=county per capita personal income in the i^{th} county for the m^{th} missing year.

$s_{i,t}$=the i^{th} county's share of state per capita personal income in the year t.

$s_{i,k}$=the i^{th} county's share of state per capita personal income in year k.

y_m=state per capita personal income in year m, and $k<m<t$.

cate that intramarginal price and gas price variables do not perform as well. The personal income and marginal price coefficients have a expected *a priori* signs for a larger percentage of utilities studied than do the intramarginal and gas price coefficients. The standard errors (in parentheses) for personal income and marginal price also indicate a higher frequency of statistical significance among the coefficients having correct signs than they do for intramarginal price and gas price.

The unimpressive results with respect to intramarginal price and gas price are similar to those obtained by Taylor, Blattenberger and Verleger for the entire United States [22, p. 5-5]. There are several factors that might account for this showing. First, intramarginal price is in all cases very small relative to per capita personal income, and consequently, may be too small to have any

TABLE 2. Residential Electric Energy Demand Functions For Major Utility Companies in Illinois.

Utility	Lagged Quantity	Personal Income	Marginal Price	Intra-Marginal Price	Gas Price
1. Commonwealth Edison	0.987** (0.013)	-0.022 (0.020)	-0.160** (0.041)	0.041** (0.011)	0.073* (0.046)
2. Illinois Power†	0.327** (0.130)	0.449** (0.156)	-0.657** (0.223)	-0.254** (0.085)	-0.136 (0.344)
3. Central Illinois Light	1.028** (0.254)	0.170 (0.359)	0.545 (0.429)	-0.163 (0.203)	-1.111** (0.598)
4. Iowa-Illinois Gas & Electric	0.691** (0.161)	0.176 (0.324)	-0.589** (0.217)	0.179** (0.096)	-0.279* (0.188)
5. Central Illinois Public Service	0.185* (0.126)	0.568** (0.104)	0.464** (0.115)	-1.191** (0.252)	-1.051** (0.201)
6. Springfield City	0.308 (0.269)	1.518** (0.704)	-0.311 (0.253)	0.096 (0.127)	0.138 (0.308)
7. Entire State	0.828** (0.030)	0.166** (0.045)	-0.166** (0.038)	0.013 (0.018)	0.049 (0.049)

*Significance Level ≥ .90

**Significance Level ≥ .95

†Includes Union Electric Company's Illinois Service

significant quantitative impact. Second, natural gas was not uniformly available to electricity customers during the period of analysis. Many more households, particularly in southern Illinois, had access to natural gas at the end of the sample period than at the beginning. This latter consideration leads to a problem of misspecification.

For these reasons, a truncated demand function without intramarginal price and gas price was estimated for the state and the 15 regions. The results (Tables 3 and 4) are superior compared to the previous model. All the marginal price and income coefficients have the expected signs. For the service areas, five out of six marginal price coefficient estimates are greater than their standard errors and for the service area subdivisions, nine out of twelve estimates are greater than their standard errors. A smaller number of per captia income coefficient estimates are greater than their standard errors.

For the entire state, both the long run price elasticity estimate (-0.87) and the long run income elasticity estimate (0.81) appear to fall close to the middle of the ranges of estimates obtained by previous studies. While the ranges of elasticity values for price and income (0 to nearly -2 or 0 to nearly 2) are relatively large, recent studies by Chern and Just [1] and Taylor, Blattenberger, and Verleger [22] tend to agree with the present results and narrow the range of plausible elasticity values.

TABLE 3. Residential Electric Energy Demand Functions For Major Utility Companies in Illinois

Utility	Lagged Quantity	Personal Income	Marginal Price	LRYE	LRPE+	Mean Lag
1. Commonwealth Edison	0.913** (0.014)	0.005 (0.029)	-0.192** (0.023)	0.057	-2.207	10.494
2. Illinois Power†	0.771** (0.059)	0.235** (0.111)	-0.167** (0.055)	1.026	-0.729	3.366
3. Central Illinois Light	0.941** (0.114)	0.165 (0.228)	-0.121 (0.158)	2.797	-2.051	15.949
4. Iowa-Illinois Gas & Electric	0.788** (0.136)	0.105 (0.226)	-0.377* (0.233)	0.495	-1.778	3.717
5. Central Illinois Public Service	0.845** (0.054)	0.235** (0.111)	-0.075 (0.075)	1.516	-0.483	5.451
6. Springfield City	0.359* (0.216)	1.505** (0.555)	-0.198 (0.193)	1.888	-0.248	0.450
7. Entire State	0.824** (0.025)	0.143** (0.038)	-0.153** (0.026)	0.813	-0.869	4.682

*Significance Level ⩾ .90

**Significance Level ⩾ .95

+LRYE is long run personal income elasticity and LRPE is long run price elasticity.

†Includes Union Electric Company's Illinois Service.

Turning to the regional variations among the coefficients and corresponding long run price and income elasticities, it is evident that substantial variation exists within Illinois and the subdivided utilities. The subdivisions within Illinois Power illustrate the extent of the variations with the income coefficients, price coefficients, and long run elasticities varying respectively by multiples of greater than five, nearly two, and nearly three. In certain instances, the degree of variation may be overstated because some of the estimates appear to be implausible, reflecting problems of biasness due to the presence of a lagged endogenous variable and misspecification (leaving gas price out for those regions where gas was an available substitute for the entire period).

In spite of these problems, the estimated equations were sufficient to examine further the basic question of whether regional differences in demand responsiveness exist. Table 5 presents the F-test ratios that compare the residual sums of squares associated with aggregated and disaggregated demand functions (see Johnston [15, pp. 192-199] for test explanation). These ratios test the null hypothesis that there is a common set of slopes and intercepts among the demand functions for the subdivisions and the demand function for the utility company or among the subdivisions and for the entire state. In short, the ratios test the hypothesis that demand responsiveness is homogeneous among the regions and the aggregated area (state or utility company) as a whole. Rejection of the null hypothesis indicates that demand responsiveness is likely to be heterogeneous among the regions and the

TABLE 4. Residential Electric Energy Demand Functions for Utility Service Area Subdivisions in Illinois.

Service Area Subdivision	Lagged Quantity	Personal Income	Marginal Price	LRYE+	LRPE	Mean Lag
1a. Commonwealth Edison Chicago (City)	0.903** (0.066)	0.095 (0.204)	-0.171** (0.058)	0.979	-1.763	9.309
1b. Commonwealth Edison North Suburbs	0.921** (0.047)	0.002 (0.141)	-0.142** (0.057)	0.025	-1.797	11.658
1c. Commonwealth Edison West Suburbs	0.881** (0.066)	0.092 (0.174)	-0.185** (0.031)	0.773	-1.555	7.403
1d. Commonwealth Edison South Suburbs	0.920** (0.063)	0.048 (0.145)	-0.198 (0.005)	0.600	-2.475	11.500
1e. Commonwealth Edison Rock River	0.888** (0.110)	0.154 (0.291)	-0.163 (0.139)	1.375	-1.455	7.929
2a. Illinois Power Northern Illinois	0.707** (0.206)	1.208 (0.405)	-0.261* (0.188)	0.709	-0.891	2.413
2b. Illinois Power Central Illinois	0.698** (0.154)	0.387 (0.302)	-0.184** (0.108)	1.281	-0.609	2.311
2c. Illinois Power Southern Illinois	0.539** (0.163)	0.796** (0.341)	-0.144 (0.139)	1.727	-0.312	1.169
2d. Illinois Power† Metro East	0.446** (0.222)	1.108** (0.607)	-0.217 (0.169)	2.000	-0.392	0.805
5a. Central Illinois Public Service Western Illinois	0.817** (0.095)	0.311* (0.203)	-0.072 (0.111)	1.699	-0.393	4.464
5b. Central Illinois Public Service Eastern Illinois	0.941** (0.101)	0.097 (0.130)	-0.032 (0.130)	1.644	-0.542	15.949
5c. Central Illinois Public Service Southern Illinois	0.203 (0.168)	1.724** (0.393)	-0.149 (0.209)	2.164	-0.187	0.254

*Significance Level ≥.90

**Significance Level ≥.95

+LRYE is long run personal income elasticity and LRPE is long run price elasticity.
†Includes Union Electric Company's Illinois Service.

aggregated area as a whole. The F-tests indicate that the homogeneity hypothesis was strongly rejected in four out of five comparisons.

Given the statistical evidence of substantial intrastate variation in electricity demand responsiveness, the information obtained in the estimated mean lags (Tables 3 and 4) is of significance for policy making purposes. The mean lag length is the average number of periods that it takes for the total long run effect to occur for a one-time change in one of the independent variables. As an example of the use of this statistic, a one-time, 10 percent increase in the marginal price of electricity would — assuming the estimated long run price elasticities were accurate — lead to a 22 percent decline in residential electric-

TABLE 5. F-Statistics for Test of the Overall Homogeneity (Intercepts and Slopes) of Electricity Demand Functions for the Entire State, Individual Utility Companies and Service Area Subdivisions.

Comparisons	F-Statistic
Entire State v. Six Utilities	2.85**
Entire State v. 15 Service Area Subdivisions	3.69**
Commonwealth Edison v. Five Service Area Subdivisions	8.06**
Illinois Power v. Four Service Area Subdivisions	3.87**
Central Illinois Public Service v. Three Service Area Subdivisions	1.96*

*Signficance Level ≥ .90

**Significance Level ≥ .99

ity use in the Commonwealth Edison service area, and this change would require on the average 10.5 years to occur. The same increase in price would only produce a seven percent decline in consumption in the Illinois Power service area, but this decline would occur in only 3.4 years. These differences illustrate the importance of variablility in demand responsiveness in implementing policies that seek to control electricity consumption through rate changes.

Conclusions

A major contribution of this research has been to provide a better understanding of how the demand for residential electricity varies across regions within a state. As expected, changes in marginal price and personal income levels produced different consumer responses across the utility service areas and service area subdivisions within the state of Illinois. Thus, a statewide demand function must be used with caution in implementing any statewide policies or programs. For example, use of the statewide demand function when changing electric rate schedules across the state to encourage conservation will yield misleading results, unless the relative shares of electricity demanded by regions remain relatively constant.

A second result of this paper has been to corroborate the approach of Taylor, Blattenberger, and Verleger [22] in establishing the practical importance of proper modeling of decreasing-block electric rates for smaller-than-state regions. Because one motivation for undertaking this study was to deal properly with decreasing-block pricing of electricity, it was therefore of considerable importance to discover that the marginal price of electricity performed reasonably well in a majority of the regions examined. Further research is undoubtedly warranted in order to improve the methodology and estimates, but the principle of approaching the demand for electricity using price observations taken directly from rate schedules has been reinforced by statistical results obtained using utility company service areas and service area subdivisions as regions of analysis.

A number of directions for future research are suggested by the results obtained here. One obvious and important topic would be the formulation and testing of models to explain rather that simply identify the regional differences among smaller-than-state areas. This analysis would focus on why price and income elasticities of demand vary by area and perhaps on whether there is any systematic basis for explaining the regional variation in electricity demand responsiveness.

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