Quantifying The Regional Impact Of Weather Variations Of Electrical Energy Generation

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Introduction

In attempting to assess the impact of the severe weather during the 1976-1977 winter on energy consumption, it became painfully apparent that the sensitivity of electrical energy loads to changing weather conditions, while significant, was at best quantifiable only on a subjective basis. To be sure, studies purporting to estimate weather sensitivity exist but all possess limitations that lead to questionable conclusions. For example, all of the econometric studies done on estimating weather sensitivity came up with a national annual average, but then only for residential consumers.¹ Other studies, for example that done by the Congressional Research Service, subjectively assume that a one percent increase in weather severity results in a one percent increase in the demand for residential electrical energy. Again, the other consuming sectors are neglected. Clearly the need exists for objective estimates of the short-term regional impact of weather on electrical energy consumption, not just for residential consumers. Meeting this objective is the purpose of this paper.

A Model of Weather Sensitivity

The demand for electrical energy is affected by a myriad of factors besides weather. Such things as the stock of energy using capital goods (e.g., space heaters, electrical machinery) the price of electrical energy, the price of energy substitutes, economic activity, socio-demographic inputs and so on, are important.² Variations in these factors from one year to the next are large enough so that when they are used in an econometric model, statistical significance of the included factor is obtained (Taylor (6), (7)). In the short-run, using monthly data, such significance is rarely, if ever attained (Uri (9)). Consequently, since the concern is with the importance of weather to the exclusion of all else, the model is structured in such a fashion that other components of the set of factors affecting demand are relegated to subsidiary positions.³

Consider normalized monthly generation (which henceforth will be synonymous with total demand) for a given region over a finite horizon

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where the normalization is accomplished on an annual basis. That is, monthly generation is divided by annual generation for a series of years. The resultant values will be the proportion of annual generation occurring in a given month. To the extent that prices, economic activity, capital stock, and consumer characteristics are constant or change very slowly and regularly from one month to the next, the only factor appreciably affecting normalized monthly generation will be the weather.

This being the case, it is important to define measures of weather. Several weather variables including monthly average heating degree days,⁴ average cooling degree days, monthly average temperature, and wind speed are generally available by region from the National Oceanic and Atmospheric Administration. Preliminary analyses showed the degree day measures to be the best explanatory variables. Thus, the model is specified as

$$(1) \quad Y_t = a_0 + a_1 X_{1t} + a_2 X_{2t} + \epsilon_t$$

where Y denotes the normalized monthly generation

X_1 denotes the monthly heating degree days

X_2 denotes the monthly cooling degree days,

t denotes the period (month)

ϵ is the error term and a_0 , a_1 , and a_2 denote parameters to be estimated.

This particular functional form was selected on the basis of a simple goodness-of-fit test. Other specifications were considered (e.g., semi-logarithmic, logarithmic, and hyperbolic) but all proved to be inferior to the one selected.

In defining a measure of weather sensitivity, the one that quickly comes to mind is elasticity, which allows one to determine the percentage effect on normalized generation of, say, a one percent increase in the number of heating degree days. Formally defined for heating degree days, it is

$$(2) \quad \frac{\partial Y_t}{\partial X_{1t}} \cdot \frac{X_1^*}{Y^*} = a_1 \cdot \frac{X_1^*}{Y^*}$$

Where X_1^* and Y^* denote the average values of the variables X_1 and Y over some period. Thus, for example, if it is desired to compute the January heating degree day elasticity over a period of three years, then X_1^* represents a single arithmetic mean of the heating degree days in January for the three years of interest while Y^* is the mean of the January proportions. The cooling degree day elasticity is analogously defined.

One should be cautious to observe that what this elasticity is measuring is not the absolute change in monthly generation due to a change in weather but rather the change in monthly generation relative to total annual generation due to a change in weather. Therefore, a one percent increase in January heating degree days might result in a 0.2 percent increase in normalized January generation. In computing the magnitude of the expansion of generation, total annual generation and not total monthly generation is the base to which this factor is applied.

Data

Before presenting the estimation results of equation (1) and estimates of the elasticities, a discussion of the data is in order.

The model is implemented at the Federal Energy Regulatory Commission (FERC; formerly the Federal Power Commission) region level. Table 1 details the composition of the regions.⁵ The normalized monthly loads were constructed from hourly load data for each of the regions covering the period 1965 through 1974. Monthly and annual load duration curves were constructed from these data.⁶ Integration under these curves yielded monthly and annual generation. The normalized monthly generation was then computed by dividing monthly generation by total annual generation of the year in which the monthly generation occurred. Consequently, the sum of normalized monthly generation over a year equals one.

TABLE 1
Federal Energy Regulatory Commission Regional Classification*

Region	Contents
1	Maine, New Hampshire, Vermont, New York, Massachusetts, Connecticut, Pennsylvania, Delaware, Maryland, District of Columbia, Rhode Island, New Jersey
2	Michigan, Ohio, Indiana, West Virginia, Kentucky
3	Virginia, North Carolina, South Carolina, Tennessee, Georgia, Alabama, Mississippi, Florida
4	Minnesota, Wisconsin, Iowa, Illinois, Missouri
5	New Mexico, Texas, Louisiana, Arkansas, Oklahoma, Kansas
6	North Dakota, South Dakota, Nebraska, Colorado, Wyoming
7	Montana, Idaho, Washington, Oregon, Utah
8	California, Arizona, Nevada

*The FERC regional classification cuts across state boundaries. Hence states appearing in more than one region were assigned to the region in which more than one half of the generation occurred.

Monthly heating degree day and cooling degree day data were obtained from the National Oceanic and Atmospheric Administration on a state basis. Regional monthly data were then computed by weighting each state's contribution to the measure by its proportion of total annual generation in the region. A total of 120 observations on the weather variables is used in estimation.

Estimation Results

The first step in obtaining measures of weather sensitivity of generation is the estimation of equation (1). *A priori*, the exclusion of economic, capital stock and socio-demographic variables would be expected to introduce a marked degree of serial correlation. Such, however, did not prove to be the situation. The two weather variables fit the data exceptionally well (adjusted R^2 were in the range of 0.85 to 0.93). Additionally, the absence of serial correlation was indicated for each region by the Durbin-Watson statistic.⁷ The implication of this is the following: It is well known that most economic variables tend to be serially correlated (Ames and Reiter (1)). If a significant serially correlated variable has been excluded from the set of explanatory variables, obviously its influence will be reflected in the random variable, ϵ . Since this serial correlation is absent in the current estimates one is safe in concluding that the failure to include, e.g., prices is not particularly damaging to the statistical properties of the estimates of the coefficients a_1 and a_2 in equation (1). The estimates were obtained by ordinarily least squares and are presented in Table 2.

The actual measures of weather sensitivity, the heating degree day and cooling degree day elasticities, were computed based on equation (2). Because the desire is for monthly elasticities (e.g., a heating degree day elasticity for January), the average number of heating degree days, number of cooling degree days, and normalized monthly loads for each month over the period 1965 through 1974 were used. The results are presented in Table 3 and Table 4.

These results are very creditable in light of other studies which measure degree day elasticities. In the best of the residential energy demand studies done to date, Taylor, Verleger, and Blattenberger [8] find an annual heating degree day elasticity of electrical energy consumption for the aggregate United States of 0.066 and a cooling degree day elasticity of 0.033. Since the elasticity concepts vary slightly (theirs being the traditionally defined elasticity of kilowatt-hour sales), a direct comparison is not possible.

An interesting comparison, however, is between the estimated elasticities and the saturation level of energy-consuming capital stock in each region. One would expect that generation of electrical energy in regions with a high saturation of central space heaters, for example, would be quite sensitive to changes in heating degree days. Similarly, generation

TABLE 2
Estimation Results for Equation (a) (1)

Region	a ₀	a ₁	a ₂	R ^{2(b)}	D.W.
1	0.7608E-01 (c) (0.7709E-03)	0.8108E-05 (0.9942E-06)	0.5622E-04 (.4751E-05)	0.8475	1.83
2	0.7764E-01 (0.7486E-03)	9.7528E-05 (0.9488E-06)	0.3129E-04 (0.4365E-05)	0.8647	1.82
3	0.6915E-01 (0.9411E-03)	0.2390E-04 (0.1921E-05)	0.5552E-04 (0.3201E-05)	0.9253	2.23
4	0.7490E-01 (0.7997E-03)	0.7546E-05 (0.8929E-06)	0.6312E-04 (0.4457E-05)	0.9398	2.41
5	0.6531E-01 (0.1069E-02)	0.1671E-04 (0.2209E-05)	0.7883E-04 (0.3088E-05)	0.9022	2.32
6	0.7237E-01 (0.9774E-03)	0.1001E-04 (0.1039E-05)	0.1146E-03 (0.7688E-05)	0.8575	2.42
7	0.7083E-01 (0.8316E-03)	0.2196E-04 (0.1224E-05)	0.7465E-04 (0.1053E-04)	0.8735	1.86
8	0.7811E-01 (0.8992E-03)	0.2742E-05 (0.2307E-06)	0.7096E-04 (0.5351E-05)	0.8684	2.11

(a) standard errors of estimates in parentheses.

(b) adjusted R²

(c) —XX denotes 10^{-xx}

in regions with little or no central space heating load would not be sensitive to such variations.

Table 5 presents regional saturation levels of central space heaters and room air conditioners for 1973. (Estimates of saturation levels for central air conditioners do not currently exist. One would expect, however, a high correlation between the number of central air conditioners and the number of room air conditioners across regions.) A regional saturation level for a specific energy using capital good is defined to be the number of housing units having the specific capital good divided by the total housing stock in a specific region. The saturation level for central space heaters must, of course, lie between 0 and 1 since no house will possess more than one central space heater while it is possible for the saturation level of room air conditioners to exceed one. A single housing unit might have an air conditioner for several of its rooms. The regional heating degree day elasticities of Table 3 are consistent with the central space heating saturation levels in Table 5. Region 7 (Pacific Northwest), and Region 3 (South Atlantic) have the highest saturation levels and are simultaneously the most responsive to a change in cold weather. Alternately, Region 8 (Pacific Coast) with a low space heating saturation level is minimally responsive to cold weather variations.

TABLE 3
Normalized Heating Degree Day Elasticities

Region	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
1	0.1091	0.1057	0.0824	0.0527	0.0252	0.0033	0.0005	0.0010	0.0093	0.0360	0.0665	0.0890
2	0.1015	0.0964	0.0724	0.0414	0.0203	0.0034	0.0006	0.0012	0.0081	0.0315	0.0623	0.0832
3	0.1769	0.1712	0.1142	0.0443	0.0152	0.0011	0.0000	0.0000	0.0047	0.0411	0.1081	0.1497
4	0.0227	0.1103	0.0829	0.0473	0.0231	0.0046	0.0010	0.0019	0.0109	0.0343	0.0722	0.0992
5	0.1504	0.1330	0.0842	0.0269	0.0067	0.0007	0.0001	0.0003	0.0036	0.0248	0.0758	0.1179
6	0.1618	0.1476	0.1240	0.0853	0.0454	0.0156	0.0035	0.0047	0.0314	0.0663	0.1129	0.1432
7	0.2327	0.2034	0.1835	0.1516	0.0908	0.0446	0.0167	0.0178	0.0586	0.1263	0.1786	0.2165
8	0.0186	0.0156	0.0131	0.0104	0.0047	0.0018	0.0002	0.0002	0.0010	0.0045	0.0114	0.0180

TABLE 4
Normalized Cooling Degree Day Elasticities

Region	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
1	0.0	0.0	0.0001	0.0001	0.0158	0.0812	0.1545	0.1341	0.0589	0.0032	0.0	0.0
2	0.0000	0.0	0.0013	0.0011	0.0194	0.0627	0.0919	0.0751	0.0356	0.0042	0.0	0.0000
3	0.0173	0.0112	0.0284	0.0513	0.1203	0.2021	0.2493	0.2297	0.1724	0.0697	0.0184	0.0150
4	0.0	0.0	0.0023	0.0023	0.0406	0.1294	0.1859	0.1486	0.0573	0.0116	0.0	0.0000
5	0.0118	0.0092	0.0483	0.1038	0.2031	0.3279	0.3728	0.3461	0.2603	0.1086	0.0236	0.0075
6	0.0	0.0	0.0011	0.0001	0.0261	0.1239	0.2260	0.1757	0.0440	0.0026	0.0	0.0
7	0.0001	0.0	0.0000	0.0	0.0048	0.0325	0.0919	0.0886	0.0226	0.0001	0.0	0.0
8	0.0002	0.0009	0.0033	0.0059	0.0288	0.0829	0.1674	0.1737	0.1056	0.0305	0.0040	0.0

TABLE 5
Central Space Heater and Room Air Conditioner Saturation Levels, 1973

Region	Space Heat	Air Conditioning
1	0.053	0.302
2	0.071	0.262
3	0.271	0.485
4	0.057	0.398
5	0.122	0.508
6	0.081	0.318
7	0.297	0.131
8	0.054	0.209

Source: Calculated from Verleger and Iascone (10)

Similarly, regional cooling degree day elasticities are consistent with air conditioner saturation levels. Region 5 (Southwest), and Region 3 (South Atlantic) have the highest saturation levels and the greatest responsiveness to changes in warm weather. On the other hand, Region 7 (Pacific Northwest) has the smallest regional saturation level of air conditioners and also the smallest response to warm weather changes.

All of this indicates that the estimates of regional normalized heating degree day and cooling degree day elasticities are consistent with *a priori* expectations.

The Cost of Colder than Normal Month

Nationally, January 1977 averaged 14 percent colder than January 1976 and 24 percent colder than normal (based on a 45 year average). Given this, an important question is: What was the increase in the cost of electrical energy to consumers as a result? Table 6 presents the change in weather (heating degree days) over the previous year. The product of this increase in heating degree days and the monthly heating degree day elasticity for a given region⁹ will give the percentage increase in generation due to the weather. The product of this and 1976 generation will give the absolute increase in January 1977 generation attributable to the weather. Applying a unit cost to this increase will yield the pecuniary cost of a cold January. This is done for each of eight regions. Region 8 (California, Arizona, and Nevada) experienced a warmer than normal weather while the balance of the conterminous states were colder than normal.

The increase in annual generation is also presented in Table 6 and reflects the product of percentage colder weather and the normalized

TABLE 6
Cost of a Cold January 1977

Region	Percent colder than January 1976	Percent Increase in Annual generation due to colder January	Increase in Generation due to colder January (mil. of Kwh)	Cost of colder January (in millions Dollars)
1	7.86	0.86	3143	\$128.9
2	23.56	2.39	7321	197.7
3	22.87	4.05	15897	461.0
4	18.92	2.32	4978	129.0
5	29.16	4.39	13713	289.9
6	13.16	2.13	917	21.4
7	10.11	2.35	3129	68.8
8	-13.83*	-0.26	-451	-9.5

*The negative sign indicates that the weather was milder than the previous year.

regional heating degree day elasticity. Thus, for example, total annual generation in 1977 increased 4.05 percent in FERC Region 3 over its 1976 level because of an increase of 22.87 percent in the number of heating degree days. Note that generation fell in Region 8 because of the milder than normal weather but that this fall is minimal because of the modest heating degree day sensitive load.

The next step in computing the cost of a severe January is to compute the product of the percent increase in annual generation due to cold weather and actual 1976 generation. This is reported in Table 6.

The actual estimation of the cost of a colder January is accomplished by computing the product of the increase in generation due to the colder weather and the average price of a kilowatt-hour (kWh) in January 1977. Since regional prices are not currently available, average 1975 regional prices were inflated by the increase in the January 1977 national price over the average 1975 price.¹⁰

The regional costs are quite substantial, ranging between a reduction of \$9.5 million in Region 8 to a dramatic increase of \$461.0 million in Region 3. The increase in the pecuniary cost of the severe January 1977 weather to the nation as a whole was \$1.29 billion.

The estimated impact of changes in weather on electrical energy generation are quite substantial. How does the estimate obtained here compare with the estimates obtained by others? A number of studies exist purporting to estimate the cost of the severe weather. The majority of those are *ad hoc*, being based primarily on a subjective evaluation. One objective study, however, was that done by Curtis and Rodgers (2).

They estimated the cost of a 29 percent more severe winter (based on heating degree days) for the heating season (October 1976 through March 1977) to be \$3.0 billion.¹¹ Included in their calculation was just the space heating load for residential and commercial consumers. The result obtained in this study, while consistent with the Curtis-Rodgers figure, is larger because the industrial and other sector consumers are included and because total load response is being measured. Clearly, the energy consumption of electric water heaters, for example, increases as the weather becomes colder.

An Alternate Specification

What has been estimated and discussed in the foregoing sections are monthly normalized elasticities. Also of interest are normalized peak elasticities, where the normalized peak variable is defined as the monthly peak system load divided by the total annual generation.

A model analogous to that in equation (1) was defined and estimated and the weather elasticities were computed. The peak elasticities were slightly larger than those obtained when the monthly normalized values were used. This is precisely what one would expect given that the energy using capital goods contributing to the peak load, (e.g., air conditioners and space heaters) are those that are most weather sensitive. Upon statistically testing the difference in elasticities, however, the null hypothesis that the elasticities are equal at the 95 percent level could not consistently be rejected. (In about 90 percent of the cases, the null hypothesis of equality was not rejected).

Conclusion

The foregoing analysis has provided estimates of the regional impact of weather variations on the generation of electrical energy. Specifically, FERC regional heating degree day and cooling degree day elasticities on a monthly basis have been estimated from time series data covering the period January 1965 through December 1974. Not surprisingly, regions with a high saturation of central space heaters and air conditioners are most responsive to variations in the weather. Finally, the results indicate that the severe January 1977 weather increased the expenditures on electrical energy consumption by \$1.3 billion.

FOOTNOTES

¹¹For example, Taylor, Blattenberger and Verberger (8), Uri (9), Halvorsen (3), (4), and Hirst, et. al. (5).

²The author is aware of the concept of "design temperature." While it is recognized that the capital stock of energy-using appliance and machinery is sensitive to this temperature variable *ex ante* (i.e., before the capital stock is in place), difference in regional responses to weather changes will be adequately reflected in

how the capital stock responds to degree day variation, *ex post*. While many weather variables exist, the ones selected here are those commonly used.

³Other variables were considered in preliminary analyses and proved to be uniformly insignificant. This is the reason why one finds a discussion of the absence of serial correlation and its implication in the paper. Because of this, a Zellner SUR approach was not used.

Also, the regional results proved to be significantly different. This is evident from the results presented in Table 2.

⁴A degree day is a unit measuring the extent to which the outdoor mean (average of maximum and minimum) daily dry-bulb temperature falls below (in the case of heating) or rises above (in the case of cooling) a base of 65 degrees Fahrenheit.

⁵The regions were selected based on the highest level of disaggregation of the data available. The Federal Energy Regulatory Commission (formerly the Federal Power Commission) performs almost all of its analysis based on these regions. It was previously determined that for electrical energy this is the optimal regional configuration.

⁶A load duration curve is a plot of the load demanded on a system against the percentage of the time that this load is equalled or exceeded.

⁷The D.W. statistic was in the range 1.82 to 2.42 for all eight FERC regions.

⁸The average of X_i^* for example, for January was $X_i^* = \sum_{i=1}^{10} X_i^1 / 10$, where X_i^1 represents

the number of heating degree days for January of 1965, X_i^2 represents the number for January of 1966, and so on.

⁹Weighted by a state's contribution to total generation.

¹⁰This increase was 10 percent.

¹¹This is their upper bound, engineering estimate.

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