# The Effect of Time-of-Use Rates: Facts vs. Opinions

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Rand

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# PREFACE

In studies published in 1977 and 1978, Rand researchers analyzed the potential effects of time-of-use (TOU) pricing of electricity for commercial and industrial customers in the United States. Quantitative estimates were based on load changes observed in European countries that have used TOU rates for many years and on the amounts of electricity used in U.S. manufacturing industries.

In a September 1980 article in *Public Utilities Fortnightly,* Hans E. Nissel questioned these calculations and reaffirmed his view that time-of-use rates "do not work."

This report reviews those estimates and finds that calculations for 5 of the 17 industries were indeed in error. The corrected values, however, leave unaltered the fundamental conclusion of Rand's initial analysis as well as of 10 other empirical studies: TOU rates do change load curves. Furthermore, Nissel's assertion that TOU rates are of no value is incorrect.

An abbreviated version of this report appeared in *Public Utilities Fortnightly,* April 23, 1981. This report includes additional material, primarily in Sec. III.6 and Sec. IV. There the authors examine the reasons that virtually all empirical studies find that TOU rates affect load curves, whereas Nissel reaches the opposite conclusion.

This report should be of interest to utility rate analysts, forecasters, and regulatory officials who wish to understand the potential effects of TOU rates. It should also be of value to participants in ratemaking deliberations who seek to understand the alternative approaches to estimating these effects. Readers particularly interested in European experience with TOU pricing should take note of the sections that correct Nissel's erroneous statements.

Preparation of this report was supported by grants from The John A. Hartford Foundation, the Ford Foundation, and the National Science Foundation.

# SUMMARY

The costs of generating and supplying electricity vary by time of day and by season. Consequently, time-of-use (TOU) rates will more accurately reflect these variations in cost and may lead to improved efficiency in the use of energy resources. The estimated magnitudes of such potential savings rest upon empirical measurements. In earlier Rand studies we examined how TOU rates altered the load curves of commercial and industrial customers in Europe and calculated the potential load changes if U.S. industries were to exhibit a similar degree of responsiveness. In a May 1980 journal article, we reviewed the findings of these and ten other studies of European and U.S. experience with TOU rates.

Subsequently, Hans E. Nissel identified a calculation error in one of our early studies and restated his view that "price signals do not work." This report corrects the earlier estimates of the potential impacts and then examines the validity of Nissel's many assertions about peak-load pricing.

In our original estimates for the United States, we calculated that TOU rates similar to those in France and the United Kingdom would have the potential to reduce peak-period loads by between 15 and 35 percent. The corrected values are reductions of 14 to 25 percent. Our basic conclusions remain unaltered: Industries change electricity use in response to TOU rates, and the magnitude and economic significance of these load shifts are substantial.

Nissel's principal assertions about peak-load pricing are that price signals do not work, that peak-load rates do not produce any energy or capacity savings, and that much of European industrial experience is not relevant to U.S. deliberations. The facts decisively refute each of these assertions.

Nissel's method of analysis relies heavily on unpublished and personal communications. Many of his statements cannot be corroborated by independent analysts. However, in instances in which the primary materials have been obtained, Nissel's statements turn out to be highly misleading and unsupported by the primary sources. His conclusions do not correspond to those reached by empirical research.

Applying and modifying TOU rates for U.S. utilities poses new challenges to energy analysts. TOU rates are generally applied first to the largest industrial and commercial customers. Because the potential changes in loads and revenue can be substantial, utilities and regulators demand quantitative forecasts of these potential effects. When U.S. experience was very limited, analysts of necessity turned to the only empirical evidence available—that for European utilities and customers—and the applicability of foreign experience to U.S. conditions was a legitimate matter of concern. Today, more than 10,000 of the larger commercial and industrial customers in the United States pay for electricity under TOU rates. This major source of empirical evidence permits utility forecasts to be firmly based on factual analysis.

# ACKNOWLEDGMENTS

We thank Stan Besen, Frank Camm, Patricia Danzon, Michael Francony, Willard Manning, and Yvette Pioger for their comments on drafts of this report, and Joyce Davidson and Karl Schwenkmeyer for their research assistance. Will Harriss's editorial skills improved the exposition at several points. We are grateful to The John A. Hartford Foundation, the Ford Foundation, and the National Science Foundation, whose grants supported our research. Responsibility for the opinions expressed herein, and for any remaining errors, of course rests with the authors.

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## FIGURE



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# I. INTRODUCTION

In an article published last year in *Public Utilities Fortnightly,*[1] we reviewed empirical evidence from 12 studies of time-of-use (TOU) rates in six utility systems: four in the United States plus the national utilities of England and France. We concluded that in every case TOU rates have changed load curves—by reducing peak loads, increasing off-peak loads, or shifting loads from peak to shoulder and off-peak hours.

Subsequently, Hans E. Nissel[2] identified a calculation error in one of the studies—one that we coauthored in 1978. Had Nissel confined himself to rectifying that error, his article would have been a useful contribution. Instead, he proceeded to disregard all empirical evidence and reiterate his views, previously published in May 1979, that "price signals do not work" and "Peak-load rates are ... not a suitable device for producing capacity or energy savings."[3] Peak-load pricing, in the words of the editor of *Public Utilities Fortnightly,* remains controversial.[4]

In this report we correct the error in our 1978 calculation. Although the correction reduces the estimated maximum potential effects of nationwide TOU rates for large industrial customers, it does not alter the fundamental conclusion that TOU rates *do* change load curves. We then confront Nissel's many assertions about peak-load pricing with empirical evidence. In each case, the facts decisively refute his opinions. Finally, we briefly discuss issues that face U.S. utilities as TOU rates become more widespread.

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[1]"Do Time of Use Rates Change Load Curves? And How Would You Know?" by Jan Paul Acton and Bridger M. Mitchell, 105 *Public Utilities Fortnightly* 15, May 22, 1980.

[2]"Peak-Load Pricing, Facts and Fancy," by Hans E. Nissel, 106 *Public Utilities Fortnightly* 17, September 11, 1980.

[3]"Federal Rate Design Standards and Energy Conservation," by Hans E. Nissel, 103 *Public Utilities Fortnightly,* May 24, 1979, p. 24 and p. 23.

[4]"A Controversy on Peak-Load Rates Continues," 106 *Public Utilities Fortnightly* 4, September 11, 1980.

## II. A CORRECTION TO A 1978 RAND STUDY

In Chap. 8 of *Peak-Load Pricing,*[1] coauthored with Willard G. Manning, Jr., we reported estimates of the nationwide effect of a hypothetical six-hour peak-load rate for all industrial customers, with economic incentives similar to the TOU rates in France and the United Kingdom.[2] We calculated a range of potential reductions in peak-period consumption based on four methods of analyzing load curves from 17 industries in France and the United States. In August 1980, when the editor sent us a draft of Nissel's September 11 article, we discovered an error in the calculations that significantly affected our estimates for five of these industries. We regret the error and report corrected values below.

As corrected, the potential nationwide reductions in the peak-period load of U.S. industrial customers range from 14 to 25 percent, not from 15 to 35 percent as previously published. However, the revised upper value of 25 percent does not change the basic conclusions reached in our book, namely that:

- Industries change load curves in response to TOU rates;
- The magnitude of load response varies widely across industries; and
- The economic significance of potential load changes in the United States is substantial: several hundred millions of dollars of fuel savings annually and, in the long run, several billions of dollars of savings in both capital and operating costs.

The 10 non-Rand empirical studies reviewed in our May 22 article are not affected by the correction of this computational error. They employed different analytic techniques from ours and applied them to different data. These other studies all found that TOU rates change load curves.

In the remainder of this section, we present details of the corrected calculation and the economic significance of the revised numbers. We conclude by contrasting the corrected numbers with Nissel's assumption of no impact. In Sec. III we examine Nissel's approach to the "analysis" of peak-load pricing.

### CORRECTED CALCULATIONS

To estimate the potential effects of TOU rates in the United States, we carried out two separate studies: one of California industries,[3] the second of all U.S. industries.[4] French load curves from 17 groups of industries under TOU demand and energy rates were compared at peak and off-peak hours with the load curves of customers in the same industries in California facing conventional rates. (See Table 1.) Two types of French industrial load data were

[1]*Peak-Load Pricing: European Lessons for U.S. Energy Policy,* by Bridger M. Mitchell, Willard G. Manning, and Jan Paul Acton, Ballinger, Cambridge, Mass., 1978. Hereafter cited as *Peak-Load Pricing*.

[2]The estimates were presented in Table 35 of *Peak-Load Pricing*. A summary of those estimates and their economic significance was presented in Table 36 of *Peak-Load Pricing* and was also included in the report *Projected Nationwide Energy and Capacity Savings from Peak-Load Pricing of Electricity in the Industrial Sector,* by Jan Paul Acton, Bridger M. Mitchell, and Willard G. Manning, Jr., The Rand Corporation, R-2179-DOE, June 1978. The detailed information contained in Table 35 is not presented in report R-2179-DOE as referenced by Nissel.

[3]*Electricity Pricing and Load Management: Foreign Experience and California Opportunities,* by Bridger M. Mitchell, Willard G. Manning, and Jan Paul Acton, The Rand Corporation, R-2106-CERCDC, March 1977.

[4]*Peak-Load Pricing,* Chap. 8.

available, one for subscribed maximum demand and the other for observed demand. For each type of data, two alternative calculation techniques could be used to project U.S. load changes. In all, we used four alternative methods to calculate load changes and reported estimates based on each. Because no single method can measure the full reduction in peak loads in all circumstances, we summarized our findings using the estimate that yielded the largest reduction in each industry.

Methods 1 and 2 assume that the French industry's load reduction is the difference between its peak and off-peak loads as a percentage of peak load, and calculate that the U.S. load reduction will be the same percentage of the U.S. industry's peak-period consumption. Methods 3 and 4 assume that during peak periods the U.S. industry will use the same percentage of its daily energy consumption as does the corresponding French industry.[5]

The California estimates employed the correct method of calculation. The national estimates, however, which were calculated by scaling up the California magnitudes using U.S. electricity consumption in each industry, contained an error that was unknowingly carried forward from an intermediate, subsequently rectified, California worksheet and that came to light in August 1980. The error significantly affected the results of Methods 3 and 4. Table 1 reports the correct national values of reductions in peak loads in the form of percentages and peak kWh at 1976 levels. For four industries—rubber and miscellaneous products, cement, blast furnace and steel works, and electronic components and accessories—the corrected values are approximately one-half of those printed in Table 35 of *Peak-Load Pricing*. In a fifth industry—ship and boat building—the corrected load reduction is larger than previously reported. Minor changes occur in several other industries. The net effect is to reduce the estimated range of potential load reduction from the initially reported 15 to 35 percent to a range of 14 to 25 percent of all electricity used during a six-hour peak period.

## ECONOMIC SIGNIFICANCE OF POTENTIAL LOAD REDUCTIONS

To reflect the variation across different U.S. utilities in the economic benefits of potential load reductions at peak hours, we considered a range of differences in the marginal costs at peak and off-peak hours. The intervals we used were 1¢/kWh to 4¢/kWh for short-run (fuel and operating) cost differences, and 3¢/kWh to 7.8¢/kWh for long-run (fuel, operating, and capital) cost differences. We applied these costs to the potential load reductions calculated from the method yielding the largest reduction in peak-period load. Due to the error in calculating the nationwide load reduction, the estimated cost savings in Table 36 of *Peak-Load Pricing* are also in error; the correct values are shown in Table 2.

Our original calculations were made at 1976 levels of energy use and costs. By late 1980, aggregate electricity consumption by industrial and commercial customers had grown more than 13 percent, while inflation-driven costs per kWh were up substantially more than 50 percent.[6] At 1980 prices, the potential effects of TOU rates applied to the manufacturing sector would be peak-period load reductions of 35 billion kWh per year, with annual cost savings of \$0.5 to \$2.1 billion in the short term and \$1.6 to \$4.1 billion with long-term adjustments.

[5]Methods 1 and 3 differ from Methods 2 and 4, respectively, on the basis of the French data used for calculation. Methods 1 and 3 use French subscribed load data and the latter set use observed load data.

[6]*Monthly Energy Review,* February 1981, pp. 65, 89. Sales to commercial and industrial customers increased 12.5 percent between 1976 and the end of 1979; aggregate electricity sales in the first 11 months of 1980 increased an additional 0.9 percent over the first 11 months of 1979. *Average* retail electricity rates to commercial and industrial customers increased 66 percent between 1976 and November 1980. Fuel costs, which are a more important factor in changes in *marginal* costs of supply, rose much more sharply. Average utility fossil fuel costs rose 74 percent and purchased oil costs rose 131 percent. An assumed 50 percent increase in marginal costs is therefore conservative.

Table 1

PROJECTED EFFECTS OF TIME-OF-DAY PRICING ON ANNUAL ELECTRICITY USE IN U.S. MANUFACTURING INDUSTRIES, 6-HOUR PEAK PERIOD AT 1976 LEVELS

| SIC | Industry | Annual Use (million kWh) | Weekday Use Noon-6 PM (million kWh) | Percentage Reduction in Peak Period Consumption | | | | | Decrease in Peak Load if Largest Percentage Reduction Applies (million kWh) |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Method 1 | Method 2 | Method 3 | Method 4 | Largest Percentage Reduction | |
| 22 | Textile mill products[a] | 31,125 | 5,540 | 14 | 0 | 14 | 0 | 14 | 776 |
| 26 | Paper and allied products | 43,591 | 7,759 | 13 | 11 | 13 | 11 | 13 | 1,011 |
| 281 | Industrial inorganic chemicals | 94,094 | 16,655 | 13 | 18 | 7 | 11 | 18 | 2,998 |
| 282 | Plastics[a] | 17,005 | 3,036 | 9 | 4 | 9 | 4 | 9 | 272 |
| 291 | Petroleum refining | 28,125 | 4,894 | 24 | 14 | 15 | 6 | 24 | 1,172 |
| 300 | Rubber and miscellaneous products | 19,030 | 4,415 | 15 | 0 | 30 | 0 | 30 | 1,325 |
| 324 | Cement (hydraulic) | 10,632 | 2,190 | 32 | 30 | 35 | 33 | 35 | 763 |
| 331 | Blast furnace and steel works | 62,347 | 12,843 | 33 | 38 | 36 | 40 | 40 | 5,128 |
| 332 | Iron and steel foundries[a] | 9,829 | 1,750 | 23 | 11 | 23 | 11 | 23 | 405 |
| 364 | Electric lighting and wiring equipment | 2,506 | 466 | 0 | 0 | 3 | 0 | 3 | 12 |
| 366 | Communication equipment | 6,021 | 1,734 | 0 | 0 | 36 | 36 | 36 | 618 |
| 367 | Electronic components and accessories | 6,455 | 1,381 | 0 | 0 | 13 | 0 | 13 | 185 |
| 371 | Motor vehicles and equipment | 20,000 | 5,760 | 0 | 0 | 36 | 0 | 36 | 2,047 |
| 373 | Ship and boat building and repairing | 2,025 | 518 | 0 | 0 | 26 | 0 | 26 | 134 |
| 379 | Miscellaneous transportation equipment | 641 | 171 | 0 | 0 | 33 | 0 | 33 | 56 |
| 381 | Engineering, laboratory, scientific and research equipment | 589 | 130 | 0 | 0 | 15 | 0 | 15 | 20 |
| 384 | Surgical, medical and dental | 959 | 326 | 0 | 0 | 44 | 0 | 44 | 145 |
| Total of 17 industries | | 355,020 | 69,568 | 16 | 15 | 20 | 14 | 25 | 17,067 |
| Other industries | | 287,546 | 56,346 | 16 | 15 | 20 | 14 | 25 | 13,868 |
| Total | | 642,566 | 125,911 | 16 | 15 | 20 | 14 | 25 | 30,935 |

[a]Load study data available for the industry in French sample but not in California sample.

Table 2

PROJECTED NATIONAL EFFECTS OF PEAK-LOAD PRICING FOR U.S. MANUFACTURING INDUSTRIES, AT 1976 VALUES

| Type of Effect | Extent |
|---|---|
| Reduction in peak-period electricity consumption | 30.9 billion kWh |
| Reduction in maximum electricity demand | 19.8 million kW |
| Proportion of peak demand in manufacturing industry | 25% |
| Proportion of U.S. noncoincident peak demands | 5.3% |
| Annual cost savings | |
| Reduction in short-run costs (fuel and operating costs) | \$0.3-1.2 billion |
| Reduction in long-run costs (fuel, operating, and capital costs) | \$0.9-2.4 billion |
| Construction of peak generating units | |
| Reduction in 200 MW units | 99 units |
| One-time saving in capital expenditure | \$4.0 billion |

## NISSEL'S TREATMENT OF THE CORRECTED CALCULATIONS

Nissel used the occasion of pointing out an error in our calculations, which when corrected leaves our basic conclusions unaffected, to reiterate his views on peak-load pricing. In his September 1980 article he first reduced the upper value from 35 percent to 25 percent of current peak-period load, reflecting the correction. He then assumed that other industries, accounting for almost half of the kWh consumed by U.S. manufacturing, would exhibit *no* response whatever to TOU rates—thus reducing the estimate from 25 percent to 14 percent of peak-period loads.[7] Finally, he asserted, without support, that "Consideration of [nontariff] factors would wipe out the few percent reduction, if any, remaining after the proper correction of Rand's arithmetic exercise."[8] To judge the reasonableness of his conclusions, we must review Nissel's approach.

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[7]Op. cit., 1980, p. 20.
[8]Ibid., p. 21.

# III. NISSEL'S OPINIONS VERSUS THE FACTS

Our May 1980 article summarized the principal empirical methods that have been applied to analyze the effect of TOU rates on load curves. We did not review subjective methods based solely on personal opinion, however. Hans Nissel's several *Fortnightly* articles, other writings, and testimony exemplify such an approach.

In this section we examine Nissel's major assertions and methods. His repeated assertions about peak-load pricing are that:

- Price signals do not work.
- Peak-load rates do not produce energy or capacity savings.
- The pattern of French industrial loads under TOU pricing is not relevant to U.S. deliberations because the French system peak has shifted outside of the peak-price hours.
- Peak-load residential rates are not found in European electric utilities.
- No industry can be responsive to a peak period of 12 to 14 hours.

The facts refute each of these assertions. Moreover, Nissel's method is to rely on unpublished and personal communications. His statements about these communications are highly misleading and the primary sources do not support his claims.

## 1. EFFECTIVENESS OF PRICE SIGNALS

Nissel asserts that "price signals do not work."[1] The fact is that every *empirical* study has concluded that TOU rates do affect load curves. We reviewed 12 studies; each reached the same conclusion. Moreover, although Nissel now ignores this evidence, at one time he did acknowledge the role of TOU prices in changing loads. In 1969 he wrote that "by all accounts the Green Tariff has fulfilled the expectations of EdF [Electricite de France] with respect to an improvement of load conditions."[2] And ten years later, in referring to EdF's estimates of the tariff's effect on the system peak, Nissel noted that his 1969 article "did not take issue with these estimates."[3]

## 2. ENERGY AND CAPACITY SAVINGS

Nissel asserts that "peak-load rates are . . . not a suitable device for producing capacity or energy savings."[4] Even if customers shift a portion of their load from peak to off-peak periods, while keeping the total purchases of electricity constant, he claims that "no fuel economies would be achieved, which is the major aim of the National Energy Act."[5] The fact is that when loads are shifted to off-peak hours and generating units are economically dispatched (e.g., in

[1]Op. cit., 1979, p. 24.

[2]"Incremental Cost Pricing and U.S. Utility Rates," by Hans E. Nissel, 84 *Public Utilities Fortnightly* 26, August 14, 1969.

[3]Op. cit., 1979, p. 17.

[4]Ibid., 1979, p. 23.

[5]Op. cit., 1980, p. 21. Also cf. op. cit., 1979, p. 20.

merit order), fuel consumption *is* reduced. These short-run savings are achieved by using more efficient plants to supply a greater proportion of the unchanged total quantity of energy. In the long run, a lower peak load will permit that quantity of energy to be supplied with less aggregate capacity.

## 3. PEAKING OUTSIDE OF PEAK-PRICE HOURS

From 1958 to 1978 the morning peak-price period in France was 7 A.M. to 9 A.M., despite the emergence in 1968 of the system peak at 10 A.M. Nissel claims that the occurrence of the system peak outside of the peak-price hours "invalidates the conclusions drawn by Rand from load curves dating to the mid-1970's"[6] and asserts that "the peak load rate does not at all reduce the load between 7 and 9 A.M."[7] In fact, the customer-by-customer load curves published in *Peak-Load Pricing* unambiguously demonstrate that TOU rates do change load curves at the peak-price hours, regardless of whether system peak *usage* occurs within those hours. Customers respond to the prices they face, not the condition of the system. The fundamental conclusion of our studies and the 10 others we reviewed is that TOU rates, by providing the strongest price signals at peak-price hours, change loads at those hours.

The very occurrence of the new French system peak at 10 A.M. suggested that the price signals of the Green Tariff had caused loads to shift. This was dramatically confirmed in the winter of 1979-80 when EdF changed the hours of the morning peak-price period to 9 A.M. to 11 A.M. (the evening peak-price period was changed by only one hour, 5 P.M.-7 P.M. to 6 P.M.-8 P.M.). The system immediately experienced a daily winter peak that most often occurs at 8:30 A.M., and occasionally at 11 A.M. Figure 1 shows how the relative system load curve changed between 1979 and 1980 in the third week of January. Over the four winter months, the change in the peak-price hours was accompanied by an average shift in the system load of about 900-1000 MW in the morning, and a much smaller amount in the early evening.[8] This rapid shift in the system peak is conclusive evidence that customers respond to TOU rates at precisely the hours of the peak prices.

The greatest benefits of peak-load pricing are obtained when the peak-price period is broad enough to regularly encompass the system peak hour. But even when the system peak does occur outside of the peak-price hours, TOU rates will still save capacity, unless the system peak is greater than the maximum load that would occur in those hours absent the TOU rate. Nissel asserts that "since 1968 no peak-load reduction and monetary saving can possibly be attributed to the price differentials of the Green Tariff."[9] In fact, despite the shift in the system peak hour, the Green Tariff did generate a net saving in system capacity prior to the 1979 change in the peak-price hours. The reduction in the 7 A.M. to 9 A.M. load, as estimated by EdF analysts and summarized in our May 1980 article, was at least 5 percent in the intermediate term and even more in the long term.[10] This load reduction easily exceeded the 2 to 3 percent difference between the 10 A.M. system peak load and the maximum 7 A.M. to 9 A.M. load.

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[6]Op. cit., 1980, p. 18.

[7]"The Electric Rate Question: Europe Revisited," by Hans E. Nissel, Electricity Consumers Resource Council, November 1976, p. 41.

[8]See "An Analysis of the Change in the Daily Load Curve in the Total Load of the System and in Individual or Group Consumption: An Evaluation of the Effects Produced by a Pricing Policy," by Y. Pioger, Direction des Etudes et Recherches, EdF, January 1981, HR/24-1045, and "Statistiques de la Production et de la Consommation," Direction de la Production et du Transport, EdF, 1979 and 1980.

[9]Op. cit., 1979, p. 18. Also see op. cit., 1977, p. 15.

[10]Op. cit., 1980, pp. 19, 20.

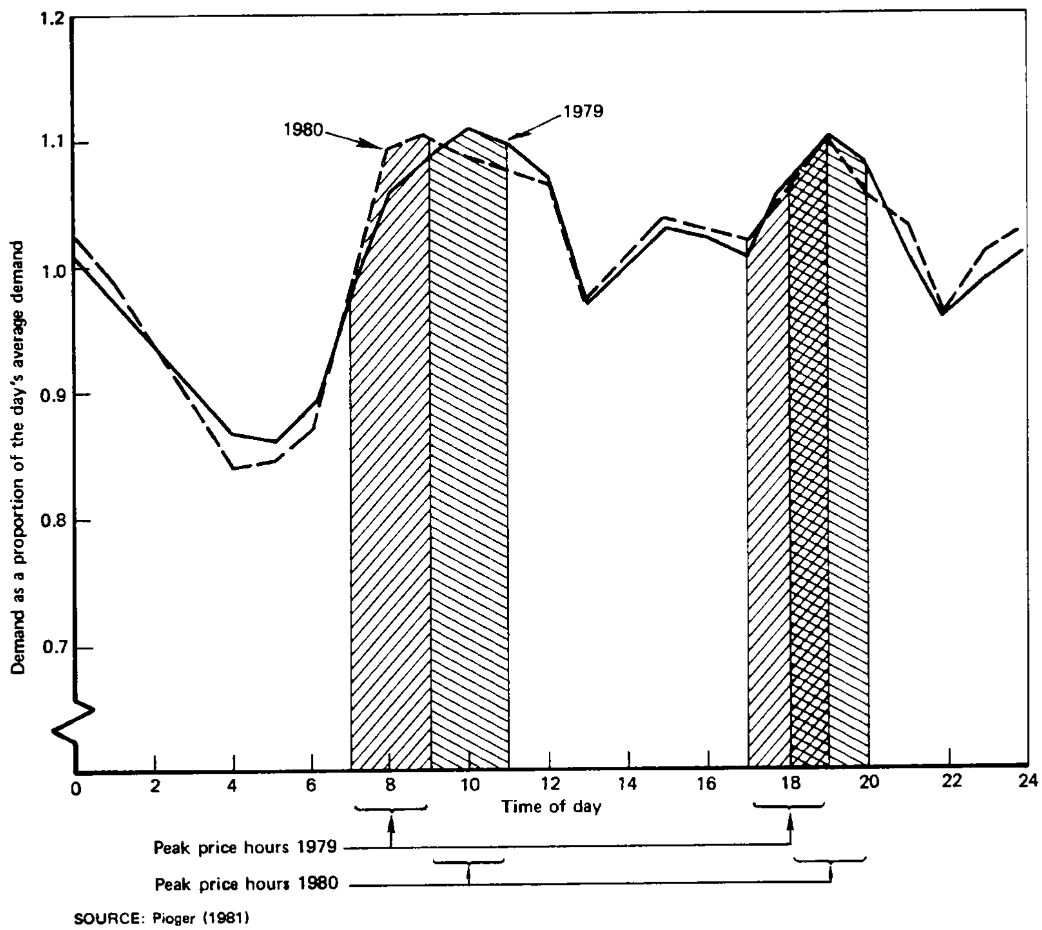


Fig. 1—Change in the shape of the French daily load curve for the third week in January

## 4. RESIDENTIAL TOU RATES

Nissel claims in his review of pricing practices in England, France, and Germany that "In none of the three countries is peak-load pricing used for residential and other low-voltage customers."[11] The fact is that each of these countries *does* offer an optional residential tariff with higher charges for electricity during peak hours of the day and lower ones at off-peak hours.[12] Customers on optional rates in England and France are not restricted in their uses of electricity, although the rate is generally cost-effective only when a customer has electric space-heating or water-heating.

[11]Op. cit., 1977, p. 17. Also cf. op. cit., 1976, p. 25.

[12]Details of the electricity rates in these and other Western European countries are found in *Peak-Load Pricing*, Chaps. 4 and 6.

Nissel further asserts that "a review of [British large industrial and commercial] rates also did not indicate peak-load pricing features."[13] The fact is that customers served at medium and high voltage levels throughout England and Wales pay rates that include time-differentiated kW and KWh charges. At lower voltage levels, customers generally have a choice between the TOU rate and a conventional rate with a maximum-demand feature.[14]

## 5. LONG PEAK PERIODS

Nissel asserts that "no industry could conceivably be responsive" to peak rating periods of 12 to 14 hours.[15] In fact, the TOU rate at the Wisconsin Power and Light Company has a 14-hour peak period, and of the four U.S. utilities we reviewed in May 1980, the greatest response was observed for customers on this rate. WP&L analysts estimate that peak-period energy use by the TOU class was reduced approximately 10 percent just one year after the introduction of the rate.[16] Moreover, large industrial customers on TOU rates in Britain generally face peak-price periods of 10 to 12 hours per day during the winter, and reduce load by percentages similar to those observed in the same industries during the two-hour peak periods in France.[17]

## 6. NISSEL'S USE OF UNPUBLISHED MATERIAL

In his articles and testimony Nissel relies on unpublished or preliminary studies, partial quotations, and personal communications. When his key statements are examined closely, they turn out to be, at best, highly misleading. The following examples are illustrative.

In his 1979 and 1980 articles, Nissel quotes and paraphrases a preliminary "draft report"[18] by the California Energy Commission that criticized a 1977 study we had prepared for that agency. In fact, as Nissel knew, none of this material was contained in the Commission's final, published report because the criticism was in error.[19]

Nissel asserts that "the great differences between France and the United States . . . make it impossible to draw conclusions for U.S. electric utilities from the claimed successes of Electricite de France" and contends that his "point of view is shared by many other utility experts, including Jules Joskow"[20] of the National Economic Research Associates. He then refers to Dr. Joskow's 1975 Senate Finance Committee testimony and Joskow's follow-up letter to Senator Haskell. In response to our inquiry about this matter, Dr. Joskow sent the original documents and wrote:

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[13] Op. cit., 1977, p. 17.

[14] These rates are published annually in the *Electrical Times Handbook* and are available from any Area Board Office. Typical forms of the rates are found in *Peak-Load Pricing*, p. 78.

[15] Illinois Commerce Commission, Case 76-0568, prepared evidence of Hans E. Nissel, February 1979, p. 66.

[16] See "Time-of-Day Rates: Design, Implementation, and Results," by James G. Miller, prepared for National Conference on the Impact of the National Energy Act on Utilities and Industries Due to Conversion to Coal, Houston, Texas, December 1978, pp. 15, 16, and Wisconsin Power and Light Company, "Report on Load Management and Time-of-Day Rates," April 17, 1978, p. 48.

[17] See *Peak-Load Pricing*, Chap. 5.

[18] Op. cit., 1979, p. 20, and op. cit., 1980, p. 19.

[19] Nissel was clearly aware of this discrepancy; the next paragraph of his 1979 article quotes from the final version of the Commission's report. Furthermore, in his prepared testimony before the Illinois Commerce Commission, Case 76-0568, op. cit., 1979, p. 67, he acknowledges that the critical material is not found in the final report; yet in his 1980 article he returns to quoting from the draft report only.

[20] Op. cit., 1980, p. 18.

> As these materials will show, the thrust of my testimony was to warn that it would be inappropriate to count on *quick* benefits from peak-load pricing in coping with the capital crunch in which the utilities found themselves in 1975. In essence, I was warning against the use of the English and French experience as a "quick fix" for that problem. It is hardly seemly of Nissel to use this warning as evidence of my agreement with his position.[21]

Nissel's accuracy in reporting private communications that relate to his assertions has been questioned by others. In 1974, Nissel appeared before the Public Utilities Board of the Province of Alberta as an expert witness for the Rural Electrification Association (REA). He concluded his six hours of testimony by alleging that ". . . the estimate of the [REA] load factor, and hence the cost allocation, was based on unsuitable and erroneously interpreted data."[22] In the process of cross-examining Nissel, counsel for another party produced Nissel's original correspondence with the Sangamo Company Ltd. Reviewing this material, the Alberta Board found that

> The written advice [Nissel] received from the [Sangamo] factory flatly contradicted the statement which he swore was correct. . . . Dr. Nissel did not voluntarily produce the letters. . . . No weight can be given to Dr. Nissel's allegation, held out by him to be based on "careful investigation," that the estimate of the REA load factor and hence the cost allocation were based on erroneously interpreted data.[23]

The Canadian rate authority summarized its assessment of this matter by saying, "The Board is gravely concerned with the propriety of Dr. Nissel's conduct in the hearing."[24]

Nissel's claims that his opinions are supported by unpublished and personal communications are repeatedly inconsistent with the facts. His distortions are a disservice to readers who do not have the time or resources to examine each original document.

## 7. CONCLUSION

When Nissel's assertions about peak-load pricing are confronted with empirical evidence, the facts contradict his views. Nissel is incorrect on such basic questions as whether TOU rates change load curves, whether altered load curves lead to fuel or capacity savings, and even whether the European countries he reviews have peak-load rates for some customers.

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[21]Letter, September 3, 1980; quoted by permission.

[22]Public Utilities Board, Province of Alberta, Decision No. 30751, Calgary Power Ltd., File No. PU 3401-II, May 15, 1974.

[23]Ibid., p. 25-26.

[24]Ibid., p. 26.

# IV. EMERGING ISSUES FOR TOU PRICING

As U.S. electric utilities move into the 1980's they face important ratemaking issues. Utilities that have already adopted TOU rates need to determine the effects of these rates, the desirability of extending the rates to other customers, and the appropriate levels of rates for TOU and non-TOU customers. Utilities without TOU rates must compare the benefits and costs of introducing TOU rates. These ratemaking issues are best addressed on a factual basis by relying on empirical data—rather than personal opinion—in conjunction with the judgment of experienced utility officials when such data are limited.

In the mid-1970's, when U.S. utilities began to consider TOU rates, the only empirical evidence on the effects of TOU rates came from abroad. Utility managers and regulators asked: How will loads respond to TOU rates? How will revenues be affected? Are TOU rates readily designed, administered, and adjusted over time? And will it be possible to achieve real load reductions, not merely a shift in the system peak hour? Indeed, in the early discussions, the notion that individual customers could and would respond to TOU rates was controversial.

The empirical evidence from 20 years of European experience with TOU rates has been encouraging. Although the response of firms has varied widely even within a single industry, the same conclusion emerged from every empirical study: TOU rates change load curves by reducing peak loads, increasing off-peak loads, or causing loads to shift from peak periods to shoulder and off-peak periods. Equally important, utilities found TOU rates feasible to design and administer. Nevertheless, some observers wondered whether, under U.S. conditions, TOU rates would lead to the same degree of response as had occurred in Europe.

Today it is no longer necessary to rely exclusively on European data. Our May 1980 article reviewed five studies by rate specialists of U.S. utilities with TOU rates.[1] In every case, the same conclusion emerged: TOU rates change load curves in the U.S. as well.

Table 3 summarizes the load changes reviewed in our May 1980 article. Overall, U.S. industrial customers are responding, after a brief period under TOU rates, in a pattern consistent with the longer-term response observed in Europe. The size of the estimated load reductions varies considerably, however. It depends on the length of time TOU rates have applied, the method of measuring TOU rate effects, and the types of industries represented. It will be several years before U.S. customers have had sufficient time to take TOU rates fully into account in designing manufacturing equipment and planning production processes. At that time, the percentage reductions in peak loads in the United States may approach those observed abroad.

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[1]Wisconsin Power and Light Company, "Report on Load Management and Time-of-Day Rates," April 17, 1978. See also "Wisconsin Power and Light Company's Experience with Large Industrial and Commercial Time-of-Day (TOD) Rates," by Steve Carlson, Wisconsin Power and Light Company, Madison, June 1978.

"Time of Day Rates: Design, Implementation and Results," by James G. Miller, prepared for National Conference on the Impact of the National Energy Act on Utilities and Industries Due to Conversion to Coal, Houston, Texas, December 5, 1978.

Pacific Gas and Electric Company, "Time-of-Use Rates for Very Large Customers, Second Annual Report," March 31, 1979. See also "Time-of-Use Rates for Very Large Customers on the Pacific Gas and Electric Company System," by S. P. Reynolds and T. E. Creighton, *IEEE Transactions on Power Apparatus and Systems,* Vol. PAS-99, No. 1, January/February 1980, pp. 147-151.

San Diego Gas and Electric Company, "Annual Report for 1978 on its Monitoring and Evaluation of the A-6 Time-of-Use Tariff," March 1979.

Southern California Edison Company, "Time-of-Use Study for Very Large Power Commercial and Industrial Customers," May 1979.

Table 3

SUMMARY OF ESTIMATED REDUCTIONS IN LOAD AT PEAK-PRICE HOURS

| Utility | Estimating Method | Type of Data | Percent Reduction in System Load | Percent Reduction in TOU Class Load | |
|---|---|---|---|---|---|
| | | | kW | kW | kWh |
| Long-term change | | | | | |
| EdF (France) | Evolution of load curve | System load | 14 | | |
| EdF | Individual customer load shapes | Subscribed demand | | 12-14 | |
| C.E.G.B. (Britain) | Evolution of load curve | System load | 13 | | |
| EdF/United States | Individual customer load shapes | Manufacturing customers | | 14-25[a] | 14-25[a] |
| Intermediate-term change | | | | | |
| EdF | Trends in hourly load | System load | 5 | | |
| C.E.G.B. | Individual customer load shapes | Load management customers | | 40b | |
| Short-term change | | | | | |
| Pacific Gas & Electric | Evolution of load curve | TOU class | | 1.3-2.0 | |
| Southern California Edison | Evolution of load curve | TOU class | | 0.6-1.6 | 0.7-1.2 |
| San Diego Gas & Electric | Evolution of load curve | TOU class | | 3.5c | 5-6 |
| Wisconsin Power & Light | Customer survey | Reported scheduling and equipment changes | | 10 | |
| Wisconsin Power & Light | Evolution of load curve | TOU Class | | | 9.7 |

NOTES: See "Do Time of Use Rates Change Load Curves? And How Would You Know?" for a discussion of these calculations. EdF = Electricité de France. C.E.G.B. = Central Electricity Generating Board.

[a]Corrected in accordance with discussion in text.

[b]Response to load management warnings above normal TOU response.

[c]Reductions in demand coincident with system peak.

The number of U.S. utilities offering TOU rates grew steadily in the mid-1970's. The Department of Energy reported recently that, as of summer 1979, some 25 utilities had TOU rates for their larger customers. Our own informal survey in fall 1980 indicates that the number now exceeds 50 and that at least 10 more utilities expect to offer TOU rates soon. Thus far, only a few utilities have subjected their TOU rates to formal cost-benefit analysis, but when they have, TOU rates have been found desirable. Furthermore, the earliest U.S. utilities to adopt TOU rates are now extending mandatory TOU pricing to additional industrial and commercial customers.

Clearly, some important issues remain for a utility considering the adoption, extension, or modification of TOU rates. The benefits of TOU rates will depend on the forecasts of load response, the importance attached to having rates reflect the costs of serving different customers, and the utility's marginal costs. Adoption of TOU rates usually requires added metering and administrative expenses. As a result, calculation of the net benefits will vary from system to system.

Once a utility has adopted TOU pricing for some customers, ongoing empirical analysis is needed to judge whether the TOU rate should be extended or modified, and whether the rates of non-TOU customers should be adjusted. And in the long term, the success of TOU pricing will depend on whether the utility is able to adjust the terms of rates in light of changing cost and usage. In some cases, this will require adjusting the rate levels for the TOU and non-TOU classes to track the costs of serving each group of customers. In other circumstances, it will require adjusting the hours of peak prices. Each of these issues emphasizes the need for objective factual analysis.

The need to update rates as circumstances change is not a new challenge for utilities, but the greater complexity of TOU pricing puts an added burden on the utility ratemaker to forecast and assess the significance of load changes. Fortunately, many of the U.S. utilities that have offered TOU rates have begun to lay the foundation for those assessments by establishing ongoing load studies.

# V. SUMMARY

In this report we have contrasted two styles of analysis: a factual, empirical approach based on load data and other quantitative information, and a non-empirical approach based on assertions not verifiable by independent investigation.

Our review of empirical studies has included 12 separate reports by utility analysts and ourselves. Because independent empirical studies often rely on different sources of data and analytic methods, it is not surprising that the studies yield a range of estimated effects. They arrive at a consistent finding, however: TOU rates change load curves. One of the studies reviewed—one we coauthored—contained a computational error that we corrected in this report. Such corrections illustrate an important strength of empirical analysis: A reader can independently examine the factual evidence and confirm, or question, the validity of the study's conclusions.

The alternative approach to examining rate effects is typified by Hans Nissel's several articles on European experience with TOU rates. Instead of conducting quantitative analysis, Nissel reports assertions and opinions about rate effects and relies on partial quotations, unpublished or preliminary studies, and personal communications. Most readers lack the primary material upon which Nissel's assertions rest and cannot independently assess the validity of his conclusions. However, when independent analysts have been able to compare Nissel's conclusions with the primary material, his statements turn out to be highly misleading and often flatly wrong.

United States electric utilities and regulators face important empirical issues for ratemaking in the 1980's. How successfully these issues are dealt with will depend to a considerable extent on whether the utility industry relies on an objective approach to these questions or one based on subjective opinion. When empirical evidence was scarce, there were few alternatives to relying on opinion. Today a growing fund of empirical evidence allows policy to be soundly based on factual analysis.

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