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CRITICAL ANALYSIS OF EUROPEAN LOAD MANAGEMENT PRACTICES

FINAL REPORT FOR
PERIOD JANUARY — JULY 1976

Date Published — January 1977

Work Performed Under
Contract No. E (04-3)-1168

MASTER

SYSTEMS CONTROL, INC.
PALO ALTO, CALIFORNIA

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

Division of Electric Energy Systems

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PERIOD JANUARY - JULY 1976**

**SYSTEMS CONTROL, INC.
PALO ALTO, CALIFORNIA**

**Sub-contractor
Systems Europe, S. A.
Brussels, Belgium**

Date Published - January 1977

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**Prepared for the
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Office of the Assistant Administrator for Conservation
Division of Electric Energy Systems
Work Performed Under Contract No. E (04-3)-1168**

ABSTRACT

Load management has been practiced in Europe for approximately a quarter century. A critical evaluation of the initial objectives and economic justifications for load management given in Europe may help energy policy makers in the United States assess the relevance of load management to meeting current energy goals in the United States.

Load management was adopted in Europe primarily to promote a growth in energy sales at a rate greater than the increase in capacity requirements. Utilities were able to improve daily load factors during the winter peak period; however, they may not have been successful in maintaining or improving their financial strength through load management. Increased capital and operating expenditures in the generation and distribution systems became necessary as the power system evolved in response to changing load characteristics. Rates charged to customers did not always produce adequate revenues from managed loads to cover the capital and operating costs to supply those loads. Comprehensive studies of the long-term costs and benefits might have prevented some of the load management problems experienced in Europe.

Load management was not introduced in Europe to reduce utility production costs, conserve energy or scarce fuels, improve the environment, or influence summer loads. Accordingly, the European experience with load management may not be relevant to energy policy makers in the United States who desire to achieve these objectives.

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PREFACE

This report presents the final results of a six-month study conducted by Systems Control, Inc. (SCI) for the Electric Energy Systems Division of the U.S. Energy Research and Development Administration (ERDA).

The study, entitled "Critical Evaluation of European Load Management Practices," was performed as SCI Project 5160 under ERDA contract E (04-3)-1168 from January 1, 1976 to July 1, 1976.

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Systems Control, Inc. wishes to thank Mr. David L. Mohre, ERDA Project Manager, for his valuable assistance throughout the course of the study.

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The Electricity Council, United Kingdom
Vereniging van Exploitanten van Electriciteitsbedrijven in
Nederland (VEEN), Netherlands
Companhia Portuguesa de Electricidade (CPE), Portugal
The Swedish State Power Board, Sweden
Electricite de France (EDF), France
Badenwerk, AG, West Germany
Rheinisch-Westfalisches Elektrizitätswerk (RWE), West Germany
Hidroelectrica Española, SA, Spain
European Economic Community (EEC), Belgium
Hamburg Electric Works (HEW), West Germany
Ente Nazionale per l'Energia Elettrica (ENEL), Italy
Compagnies Reunies d'Energie du Bassin de l'Escaut (EBES), Belgium
Union des Exploitations Electriques en Belgique (UEEB), Belgium
Unie der Kempische Electriche Centrales (UKEC), Belgium
Central Canterbury Electric Power Board (CCEPB), New Zealand

Chapter 1

INTRODUCTION

1.1 BACKGROUND

Until recently, electric utilities in the United States chose to expand generation, transmission and distribution capacity to meet increasing consumer load demands. This was possible because favorable financial and regulatory conditions permitted the utilities to install the kinds and amounts of capacity necessary to satisfy customer demands in an economic and secure manner. By contrast, load management techniques have been developed and used extensively over the past 20 to 30 years in Europe; these techniques control the electric load shape to meet indigenous constraints and corporate objectives.

Recent increases in the price of foreign oil as well as a growing recognition of the finite supply of domestic fuels have led to an increased energy awareness in the United States. One result of this energy awareness has been heightened interest by U.S. utilities in load management as a potential means of efficiently using and conserving the fuels used for electrical energy production in the United States.

Numerous papers and reports have been published on European load management practices; these papers and reports were based on overseas surveys, reviews of available literature and equipment, and studies of pilot installations in the United States. The studies focused on what was done in various European countries and inventoried the particular equipment, rates incentives and strategies implemented. There are no known reports or publications that fully examine why many European utilities chose to adopt a policy of load management. Nor is there a comprehensive and critical review of the real long-term costs and benefits for the consumer, the utility and the nation, realizable from load management strategies.

Since policy decisions on load management will have a major impact on utility expansion and consumer lifestyle in the United States, it is important to take advantage of all available information. Therefore, the study is not only a critical evaluation of the European experience with load management, but also an assessment of the relevance of load management for United States utilities.

1.2 OBJECTIVES

The study has three primary objectives:

1. To determine the reasons for European utilities choosing to manage load (as opposed to the predominant U.S. policy of providing adequate capacity to satisfy all instantaneous loads); and to

examine the finance, energy, political and social constraints which affected those decisions;

2. To analyze the economic justifications supporting load management techniques;
3. To determine the effect of load management strategies on utility planning and operations.

1.3 SCOPE

The study focuses on the use of customer load management technologies, especially storage space and water heating. A primary consideration of the study is the economic incentives offered to customers through the electric rate structure. The use of ripple control to schedule and control loads is another topic which the study addresses.

Storage heating and ripple control have been utilized to some extent in most European countries. The study examines in detail five countries where storage heating is most widespread: Belgium, France, Switzerland, United Kingdom, and West Germany. New Zealand also was surveyed because it is dominated by European cultural patterns and uses European technologies.

1.4 METHODOLOGY

The study was performed by staff from Systems Control, Inc. and Systems-Europe, S.A., the Belgian affiliate of Systems Control. The Systems-Europe staff brought to the study experience in planning and operating load management systems and industry contacts for accessing European utility data. Systems Control, Inc. assumed responsibility for final analysis of all relevant literature and preparation of the final report.

The findings and conclusions presented in this report were primarily based on discussions with European utility staffs. Thus, several references cited in this report are to the Collections of Technical Memoranda prepared by Systems Control and Systems-Europe staffs; these references document personal interviews, correspondence, and telephone conversations. The Preface acknowledges those companies that provided information.

Published literature was also reviewed by the project team. The literature in the United States and Europe centered on the promotional arguments given by equipment suppliers to the utilities and by the utilities to their customers. The published literature did not present all of the reasons which influenced the utility decision-makers who were interviewed for the SCI report.

1.5 SYNOPSIS

Chapter One gives an overview of the European Load Management Practices study.

Chapter Two presents technical background information on the general subject of load management. Important terms are defined and basic information useful in later chapters is provided. The last section of the chapter contains a brief inventory of load management concepts implemented in each of the six countries emphasized in this study. The reader familiar with the subject of load management may omit reading all or part of this material.

Chapter Three gives the reasons why European countries chose to implement storage heating and ripple control as load management techniques. The chapter is qualitative in nature.

Chapter Four reviews the European economic justifications supporting the decision to use load management.

Chapter Five gives daily and annual load factors for several European electric utilities and compares this data with utilities in the United States.

1.6 MAJOR CONCLUSIONS

Every country and utility in Europe had unique objectives, characteristics and constraints affecting its reasons for choosing to manage electric loads. Interviews with representatives of European utilities indicated that some factors favoring load management have not been reported in the literature.

The major conclusions of the study follow.

1. Load management was adopted to promote new loads, thus increasing off-peak energy sales (valley filling), and to shift certain existing loads from peak to off-peak times of the day (peak shaving).
2. Financially, valley filling in capacity-limited systems was justified to promote a growth in energy sales at a rate greater than the growth in capacity requirements; the valley filling technique improved utility financial conditions. The principal technical reason for using valley filling was to avoid off-peak shutdown and thermal cycling of generators.
3. Peak shaving was justified to defer the need for capacity additions. For utilities that had filled their daily load valleys, peak shaving was needed to reduce new system peaks occurring during periods that were previously off-peak.
4. No comprehensive economic analyses supporting the European decision for load management were located by the study team. Higher daily load factors were generally assumed to be beneficial by European utilities.
5. Controlled storage space heating (used to achieve valley filling) and storage water heating (used for peak shaving) were the primary

tools of customer load management in Europe. Centralized direct load control (ripple control) was introduced to provide operating flexibility and economy not possible with fixed-time controls.

6. Off-peak rates were offered to customers to promote storage heating. These rates were often established by determining the rate necessary to attract customers; they were not based upon the principles of marginal cost pricing.
7. European load management practices were most successful in influencing daily load characteristics during the peak season. Daily load factors of up to 95 were achieved in a few cases. Load management as practiced in Europe had a less significant effect on annual load factors than on daily load factors.
8. The occurrence of very high daily load factors resulted in the extended use of peaking generation units and the development of overloads in the distribution system.
9. No analyses showing that European electric utilities had been successful in maintaining or improving their financial strength through load management were located by the study team. Increased energy sales did improve revenues, but capital and operating costs also increased as the utility generating mix evolved in response to changing load conditions.
10. Load management presented short-term benefits to European electric utilities. The long-term effect of load management resulted in unexpected costs. Comprehensive studies of the full range of costs and benefits may have avoided some of the problems experienced in Europe with load management.
11. Load management was not introduced in Europe to reduce production costs; conserve energy or scarce fuels; improve the environment; or influence summer loads. Accordingly, the European experience with load management may not be relevant to energy policy makers in the United States who desire to achieve these objectives.

Chapter 2

TECHNICAL BACKGROUND

This chapter introduces concepts and definitions fundamental to a study of load management practices. The reader familiar with the subject may choose to proceed directly to the discussion of European practices in Chapter Three. Readers desiring a concise inventory of European procedures should reference Section 2.3.

2.1 LOAD MANAGEMENT ALTERNATIVES

Load management can be defined as any action taken by either a utility or a regulatory agency to influence or modify the characteristics of the electric load shape. Load management includes both supply management and customer load management.

2.1.1 Supply Management

Supply management modifies the apparent load shape as seen by the generators without affecting the real loads of individual customers. In Europe, pumped hydro storage is widely used where geographic conditions permit. Pumped storage displaces peaking generation capacity that would otherwise be needed. Pumped storage is most attractive when off-peak nuclear energy is used for pumping; in this case approximately 25 percent round-trip losses in pumped hydro can be justified. When fossil-units are used for pumping, the net fuel costs for energy delivered from the pumped hydro are relatively high. However, if the capital cost of the pumping facility is low, there can be a net economic advantage.

Interconnections between neighboring utilities are used in Europe to level the apparent load; for nationalistic reasons, these interconnections are not used as extensively as in the United States. North-South

ties (such as between Sweden and Denmark) balance the supply characteristics of predominately hydro-based systems with fossil-fired systems. These ties also balance the supply characteristics with varying consumption patterns caused by cultural and climatic differences. East-West ties exist in Europe but they are weak and generally used only for system security reasons.

2.1.2 Customer Load Management

Industrial Load Management. Interruptible rates are used in Europe and the United States by many large industrial customers. Under the interruptible rate concept the industrial customer is offered power at reduced rates to compensate for possible interruptions. Such contracts are desirable to the utility because they reduce the power reserve margin that the utility must maintain. Many large industrial customers in Europe have voluntarily implemented their own load control equipment to selectively cut off non-critical loads. This technique reduces peak demand for the customer and thereby reduces demand charges. The technique is used in electric energy-intensive industries such as aluminum and chlorine, and has potential use in other industries. In some European industries, companies have installed self-generation systems to limit demand on the electric utility during system peaks. Rates are structured so that the savings in demand charges offsets some of all of the costs for the customer-owned and operated generators.

Residential Load Management. Storage space and water heating are the principal means of residential customer load management [1,3] in Europe. Storage water heaters store quantities of hot water adequate for several hours of normal consumer use. The heaters, therefore, can be turned off for three to four hours without significant inconvenience to most consumers. The on and off switch of the water heaters is controlled either by a local timer or by a central control system.

Electric storage space heaters usually consist of a central core of magnesite bricks interspersed with electric heating coils. The bricks are heated to a temperature of up to 1,300°F during the nighttime hours; stored heat is drawn from the units as needed during the day. The energy stored is controlled in part by a temperature sensor on an outside wall of the building.

The thermal capacity of a storage heater may be designed to satisfy only part of a residential heating load. Direct electric heating may be used to provide a part of the heating load, thus reducing storage requirements and costs (mixed heating). Storage requirements may also be reduced by using a daytime boost to partially recharge the storage unit. Electric storage space heaters are usually controlled by either time switches or a central control.

2.2 LOAD CONTROL TECHNOLOGIES

2.2.1 Local Direct Load Control

Under local direct load control, time switches directly control specific customer loads or electric meters. Time switches let the consumers know exactly the time period when the device will be inactive. The main disadvantages of time switches are the high cost of maintenance and lack of flexibility. If left for long periods of time without servicing and resetting, small errors in timekeeping accuracy compound and cause the device to be switched on and off at undesired times.

2.2.2 Centralized Direct Load Control

Ripple control is the form of direct load control used in Europe. Ripple control is a convenient term for direct load control using audio-frequency power-line carrier for communications. It uses coded audio-frequency signals, injected into the power network, to control remote

receivers from a central location. For example, a receiver connected to a residential water heater can be used to disconnect the water heater when a certain frequency signal is received. Usually ripple control systems have about ten channels to provide control of ten separate load groups.

The ripple signals are sent via a carrier in the 150-1500 Hertz frequency range since distribution systems can adequately transmit tones over this range. To avoid possible interference by electrical noise, frequencies of harmonics are not used. The received control voltage is about one percent of the main voltage; this is generally high enough to allow the receivers to respond only to the control tone. Receivers have a one percent failure rate of per annum and a life of twenty years.

Ripple control is implemented in distribution systems with injection at voltage levels from 11 KV to 110 KV. The number of injection plants is determined by the load density--many plants with 11 KV injection may be needed for concentrated urban loads; fewer plants with injection at sub-transmission voltages would be sufficient for rural or semi-urban loads. There is a large initial cost for the injection equipment and an additional small cost per customer for the receivers. Therefore, for a given system, a minimum number of controlled customers is necessary to economically justify the ripple control system.

2.2.3 Rate Incentives

Customers using storage space or water heating incur costs for storage equipment; they may also experience inconveniences as electric service to these loads is interrupted during the peak period. Utilities offer special rate incentives to compensate for these costs and inconveniences.

Utilities in Europe have publicly justified off-peak rate incentives for storage heating maintaining that these loads use existing efficient

base load units to supply the load. In principle, storage heating customers pay the utility to cover operating costs only, while the normal rate covers both operating and capital costs.

2.3 INVENTORY OF EUROPEAN PRACTICES

This section briefly reviews the status of load management in five European countries (Belgium, France, West Germany, United Kingdom, Switzerland) and New Zealand. Although various techniques of load management have been applied in many other nations, the countries cited above exemplify most of the important features [1,3].

Belgium. Belgium uses storage space and water heating and ripple control systems to give utilities a controllable load shape. Belgium also has interruptible industrial contracts where a portion of the industrial load may be switched off during peaks or emergencies. The relative importance of the various load-leveling technologies which Belgium uses can be assessed using the 1974 winter as an example. At the time of minimum load, 8.8 percent of the load was for pumped storage, 3.3 percent for storage space heating, 1.4 percent for storage water heating, and 4.4 percent of the load was interruptible. During this time period, the minimum load was 74.0 percent of the daily peak. Peak loads in Belgium could be reduced by about five percent by voltage reductions at the distribution level.

France. France initially experimented with ripple control of storage heating in 1966 in Angers. France adopted a policy of load management because the average night and noon loads were only 27 and 55 percent, respectively, of the peak load. Increased sales without additional capacity investment were thus made possible. By 1973 the average night level had increased from 27 percent to 64 percent of the peak load, signaling an increased daily load factor. About ten percent of the residential customers had ripple controlled heaters in 1974. If the trend continues, France could become a night-peaking country in five to ten years.

West Germany. Using controlled storage space and water heating, West Germany achieved daily load factors as high as 95 percent in its major utilities during the heating season. In 1974, seven percent of German families used electric storage heating. In West Germany, load is also leveled through the use of night-use-only contracts for high capacity industrial plants.

Switzerland. Electric water heaters have been used extensively in Switzerland since the early 1920's, due, in part, to an abundance of hydro energy in this country. Compared to the European average of about twelve percent, more than 50 percent of Swiss residential customers had electric water heaters in 1958. Abruptly increased demand at the beginning of the daily low tariff period led to the adoption of a load spreading policy. This policy grouped the water heating loads into several groups with different switching times. Control was initially done by time switches but has since been replaced by ripple control.

In contrast, storage space heating has not been encouraged in Switzerland. Maximum demand occurs in the winter when river flows, and hydro energy resources, are at their annual minimum.

United Kingdom. The United Kingdom uses switch-controlled storage water and space heating. Britain has retained time-switch control while the rest of Europe has been gradually replacing this with ripple control. However, the British have historically used a different time-switch system from that used elsewhere in Europe. The British claim their time-switch system is cheaper than ripple control. In addition, Britain has interruptible industrial customers; load can be shed for up to fifty hours per year following a peak warning.

New Zealand. The predominately hydro generation and heavy winter demands in New Zealand present a situation similar to that of Switzerland. Controlled water heaters are used to control and limit the peak demands. Storage space heating is not very common.

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Chapter 3

RATIONALE FOR LOAD MANAGEMENT

3.1 STORAGE SPACE HEATING

Two major reasons were given by European electric utilities for implementing storage space heating: to increase energy sales and to avoid off-peak shut-down of generators [1,2]. Less important factors such as nationalization and lower production cost were also cited in the published literature [3-6].

3.1.1 Energy Sales

Load management was introduced in most countries to increase energy sales without providing additional generating capacity. Most storage heating customers either lived in newly constructed housing which otherwise would have used natural gas or oil-fired heating, or were conversions from fossil-fuel heating. The result of load management was that more electric energy was sold than would have been possible without storage space heating. Although some direct electric heating customers did convert to storage systems, thus shifting load from peak to off-peak (peak-shaving), the dominant objective and effect was to fill the daily load valleys with new load.

This marketing rationale for implementing storage heating is perhaps best expressed by the following statement, made in reference to England and Wales: "During the past twenty years the U.K. Electricity Supply Authorities have made a concerted effort to obtain a substantial share of the domestic central heating market by making use of a succession of heating systems which generally took advantage of reduced tariffs for power supplied at off-peak times so that such systems became economically competitive with systems based on alternative fuels [7]." Similar statements were made in other European countries studied.

Increased energy sales appear to have been sought by utilities to enhance the financial image of the company. A utility with unit sales increasing faster than requirements for new capital was attractive to investors. Simultaneous growth in demand and capacity was considered necessary for electric utilities to plan a different generation mix to meet new load conditions. Investors were willing to finance such an investment when the revenue potential of the utility improved through a larger base of energy sales. Even during the 1960's, when financing was generally available, storage heating was often promoted to improve the company image and so receive the most favorable financing conditions [2]. Competition for capital existed even in countries with nationalized electric power systems.

At the time of its introduction, storage heating appeared to offer a way to make electric utilities less capital-intensive. Rapid development of storage heating occurred in the 1960's when forecasts of maximum demand predicted a need for the doubling of installed capacity every ten years. These forecasts, converted into cost per incremental kilowatt, indicated that the investment per kilowatt-hour of energy sales was increasing and the industry was becoming more capital-intensive. By increasing sales without requiring commensurate investments it was hoped that the trend could be somewhat slowed.

In the regulated utilities which existed in Europe increased sales were not sought to maximize short-term profits. The objective of such utilities, rather, was to provide a dependable and uniform rate of return to investors. Any additional revenues were returned to customers in the form of lower rates.

Because of its market potential residential storage space heating was identified by utilities as a suitable mechanism to increase energy sales. Natural gas, widely available in many parts of Europe, could

heat a home at less cost to the consumer than direct electric heating. Some utilities became concerned that their electricity sales would not increase, or perhaps even decrease, if natural gas and fuel oil systems remained attractive in cost. Storage heating was introduced, along with special off-peak rates to compete with alternate fuels. By actively competing with natural gas and oil, the electric utilities attracted new customers. In countries or localities where the gas and electric system were managed together, this competition was not as pronounced.

Various methods were used to arrive at the day/night rate differential encouraging storage heating. With each method, the result was that the customer's monthly cost of storage equipment and electric energy was less than the price of gas alone.

Load management led to an increase in the number of all-electric homes, as homes with electric storage space heating usually also used electricity for water heating and for cooking. The residential loads led to an increase in peak period loads. To most utilities this small increase in demand was desirable because some capacity growth was considered necessary; the very large storage heating load provided a large sales base.

Storage space heating was actively promoted in those areas where it was offered. In the United Kingdom, for example, extensive press and television advertising was used. Architects and housing developers were informed of the benefits of electrical storage water and space heating. Market research was also used to ensure that householders were satisfied. Purchase taxes were removed from approved heaters and storage devices to provide additional cost incentives [8].

Figure 3.1 shows the relative contribution of residential, industrial and commercial demand to the total daily load for England and Wales; this figure is representative of Europe [10]. Residential loads were

Figure 3.1 COMPONENTS OF SYSTEM LOAD FOR
ENGLAND AND WALES, WINTER DAY IN 1960/61 [10]

generally considered desirable loads since they were less sensitive to both economic cycles and local business fluctuations than either commercial or industrial loads. By attracting increased residential load as a share of total system load, the load of a utility became more stable and some of the uncertainties in expansion planning were alleviated.

3.1.2 Off-Peak Generator Shutdown

By filling the daily load valley, the utilities avoided off-peak generator shutdown and cycling of large units. During off-peak periods when the demand was less than the peak demand, some fossil-fired units were shut down or operated at far less than capacity. In the first case daily startup and shutdown costs were incurred; in the latter case, operating inefficiencies occurred. When efficient base load units were not fully used during off-peak periods, additional load could be added to the system at low marginal costs. Storage heating systems raised the minimum off-peak loads and helped alleviate these problems. Additional benefits accrued as thermal stress and other problems associated with shutdown, startup and cycling were reduced. In Australia, "electricity disposal" was considered [11] as one way to allow large units to remain on line unless other procedures were adopted.

3.1.3 Other Storage Space Heating Benefits

Several secondary reasons, listed below, were also given as justifications for the decision to adopt load management. These benefits do not appear important enough by themselves to have justified the decision.

Lower Production Cost. During the 1960's when load management was widely adopted in Europe, economies of scale enabled each new fossil-fired unit to provide base energy at lower cost to the customer than earlier units; increased energy sales resulted in lower rates to all customers, both on-and off-peak. Furthermore, the introduction of off-

peak load in some companies permitted some existing fossil and nuclear base loaded units to be operated at capacity during the off-peak period. Efficiency thus improved and a lower average off-peak cost resulted.

Elimination of Direct Electric Heating Boosters. On the coldest days of the year, consumers with oil and gas-fired space heating systems often used portable direct electric heaters for supplemental heating. This was an undesirable load for an electric utility because it coincided precisely with the system peak and caused a need for additional installed capacity, yet it brought in little revenue to cover the cost of that generation. By encouraging the use of electric storage heating, some European utilities hoped to capture the entire heating load--with good load characteristics--not just certain undesirable parts of it. This objective has been explicitly given for France [12].

Nationalization. Some systems in Europe (notably France) were nationalized after storage heating was introduced. After nationalization, several smaller systems were merged. Since some of these small utilities had rate structures encouraging storage heating and others did not, the decisions were made to provide non-discriminatory service and thus extend the opportunity to choose storage heating to all customers.

3.2 STORAGE WATER HEATING

Controlled storage water heating was promoted as a way to reduce daily peak demands and shift existing electric energy use from peak to off-peak periods. This enabled utilities to defer the need for new capacity without increasing total energy use. Hydro-based countries like Switzerland and New Zealand experienced low load factors, but were unable to level daily loads through the promotion of storage space heating. In Switzerland, for example, river flows were at their lowest

level during the season when the space heating load was greatest. These countries were thus characterized as being both capacity and energy limited. Unlike storage space heating, which was effective in leveling daily load curves only during the winter heating season, storage water heating was able to level loads throughout the year. Controlled storage water heating was especially appropriate in Switzerland because it had the highest saturation of electric water heating and the highest per capita consumption of hot water in Europe. In other countries, both storage space heating, which increased peak energy sales through the introduction of new loads, and controlled storage water heaters, which shifted existing loads from peak to off-peak periods, were used.

3.3 ADDITIONAL FACTORS

In addition to the arguments presented above, several other reasons were given as justifications for storage heating. While some of these represented true benefits accruing from storage heating, none of them appear to have been important factors in evaluations of storage heating. Since these reasons were often cited in the literature they deserve attention.

Environmental Benefits. Environmental benefits of storage heating were cited in the promotional literature. Benefits would occur if electric storage heating displaced oil burned without environmental safeguards.

Energy Conservation. Although energy conservation was cited in promotional literature, storage heating was recognized by utilities in Europe as possibly being counter-conservation, because it tended to encourage nighttime heating, which was often not customary in Europe.

Loss Reduction. Storage heating may have reduced percent electric losses in the distribution system (if distribution load peaks were not increased) since losses are a non-linear function of load. Any savings

would be reduced, however, by inefficiencies in the energy storage systems.

Optimal Resource Allocation. Unlike the United States which has indigenous nuclear and fossil fuel resources, most European nations imported almost all of their fuel. There was no justification, other than cost, for preferring one fuel over another. The use of nuclear-generated electricity to displace direct burning of fossil fuels for heating did not lessen the dependence of these countries on imports.

Energy Crisis Solution. Although fuels have long been expensive in Europe they have always been in good supply. The use of natural gas is actually increasing in many parts of Europe [1]. The high price of all forms of energy in Europe probably contributed to the fact that per capita consumption of electricity is considerably below that of the United States. High prices had no significant impact on the decision to encourage adoption of storage heating.

Customer Comfort and Economy. Customer comfort and economy were prominent arguments used in promotional literature. Customers generally liked the quality of service given by electric heating even when storage was involved. Comfort and economy were especially promoted in Belgium and France.

3.4 PROBLEMS USING LOAD MANAGEMENT

Several problems arose with the widespread acceptance of storage heating. Some of these problems are being solved through the use of ripple control which provides greatly increased operating flexibility compared with time switches.

3.4.1 Introduction of Night Peaks

Storage space and water heating were widely accepted and implemented in those utilities where they were offered. As a result, new daily loads occurred during previous off-peak periods. Storage space heating loads occurred during the peak period of the year causing new annual peaks and creating a need for additional installed capacity.

These peaks occurred both because non-controlled loads did not materialize as quickly as had been earlier forecast and because storage heating promotional efforts were very successful. In England, for example, over an eight year period (1963-1971) electric storage heating use increased from 1115 MW to 9600 MW, an annual compounded increase of 33 percent per year [10].

3.4.2 Increased Distribution Investments

In some cases, storage heating increased the need for the investments in the distribution system. This occurred due to both large power and energy requirements. For example, if only ten percent of the customers on a feeder converted to electric storage heating from a fossil system, power requirements and energy loads could be doubled. Estimates in Belgium and West Germany showed that no more than ten to 15 percent of the dwellings could be heated by electric storage without requiring utility investments that were not compatible with existing rate structures [3,9]. In Belgium mixed space heating (two-thirds storage and one-third direct) is now promoted because up to 40 percent of all dwellings can be accommodated with mixed electric space heating without reinforcement of the distribution system [9].

The additional revenues concomitant with increased distribution loads did not cover the cost of distribution reinforcements. Special rates adopted to promote storage heating were designed in theory to

recover only operating costs, principally fuel expenditures. In practice, rates designed to compete with natural gas and oil did not, in many cases, recover all of the costs necessitated by storage heating loads.

In West Germany nighttime peaks have occurred, and France and Belgium are concerned that large nighttime peaks will occur unless some corrective actions are taken [12]. In West Germany, present policies to avoid increasing storage heating peaks include efforts to reduce the growth rate of electric heating to the growth rate of industrial load and other uses of electricity, and efforts to maintain promotional efforts only in areas where additional storage heating can be added without causing distribution investments.

3.4.3 Changing Marginal Costs

In theory, the design of off-peak rates to encourage storage heating generally priced off-peak energy at the marginal cost of production; i.e., off-peak consumers paid only fuel (or energy) costs because the likelihood of their load contributing to the need for new generation was small. In practice, rates usually were designed to compete with alternate energy sources.

Changing Off-Peak Generation Mix. As storage heating came into wide use, the most efficient, lowest cost units became progressively loaded. Eventually base loads were satisfied by less efficient units originally intended for intermediate duty. In some cases peaking units were used to satisfy base loads during the peak season.

Nighttime Peaks. As storage heating became widely accepted, off-peak users enjoying low rates actually contributed to the need for new generation capacity. The situation occurred where low rates continued to promote storage heating even though the new load required new generation investment. These developments were not compatible with the concept of marginal costing.

Increased Distribution Investments. Distribution investments were required to meet increased storage heating loads. Marginal costs, upon which rates were initially based, did not include a distribution investment component.

Supplemental Heating. Most storage space heating customers used some portable direct electric heating to boost their storage heating. The use of portable heaters occurred on the coldest days of the year when storage capacity was not sufficient, and when daytime temperatures were much lower than expected when compared to temperatures during the previous charging period. Many storage space heating systems terminated the charging cycle when the storage unit reached a temperature determined by the outside temperature. Thus, even when systems had adequate capacity, there were times when the stored energy was not sufficient. The result was a needle-peak similar to that caused when direct heating was used to supplement fossil-fired heating systems; i.e., an increase in the need for new generation capacity with insufficient revenues to recover costs. Thus, even though storage space heating customers were given low rates because of their off-peak use, these same customers did, in fact, contribute strongly through their supplemental heating load to the need for new investments.

3.4.4 Increased Financial Requirements

When intermediate or peaking units were used for extended periods for base load operation, production costs became higher than anticipated by low off-peak rates. When the condition was expected to exist for several years, one solution was to introduce new base-load units. Some utilities preferred to use the less capital-intensive, intermediate or peaking units for extended periods and pay the additional operating costs. The economics to a utility of storage heating were questionable unless efficient base units were employed when the load characteristics suggested they were needed. When the peak demands were increasing at the same rate as the load factor, new generation was justified without retiring or replacing existing units.

3.4.5 Rate Stability

Economic theory suggested that the off-peak rates be adjusted as marginal costs changed with generation and load characteristics. However, consumers, and regulatory agencies, generally required that the peak/off-peak rate differential upon which consumers justified their investment in storage equipment, remain stable. The utility was sometimes left with a rate structure which promoted additional off-peak usage even though that consumption led to a need for additional capacity.

3.4.6 Cross Subsidization

At least one European utility, with extensive use of storage heating and very high daily load factors during the heating season, claimed to have lost money on electric storage heating service. This loss was attributed to off-peak rates which could not be changed and which were too low for recovery of all costs associated with the service [9]. Utility gross revenues did not suffer because the total revenues permitted by the rate structure and regulatory agencies were sufficient to cover total costs and profits. On-peak customers apparently subsidized the low rates enjoyed by off-peak users.

3.4.7 Discrimination

Practical considerations generally required that the same rate structure options be made available to all consumers in a utility. This prevented a utility from denying storage heating service to additional customers once that additional load would no longer have a beneficial effect. Some West German utilities faced with this problem chose to discourage new customers by charging a large connection fee for new storage heating units. This created customer dissatisfaction at a later time when storage heating was again promoted. Connection fees were subsequently reduced.

3.5 RIPPLE CONTROL

As operating problems with storage heating became evident, many utilities introduced the ripple control system. Ripple control could remotely control customer loads and make operation of the storage heating systems more flexible. Ripple control alleviated some, but not all, of the problems associated with storage heating.

By using ripple systems to eliminate nighttime peaks, the utilities were able to continue promoting storage heating and thus further increase energy sales. From the utility point of view, the saturation of electric storage heating occurred much later when ripple controls were present than when time switches were used.

Ripple-based systems are flexible because they allow storage heating loads to occur at times beneficial to the utility. Some countries used ripple control to provide daytime boosts to storage units in the mid-afternoon when a small load valley occurs between the morning and evening peaks. This was beneficial to a consumer, even if the boost was at the daytime rate, because it permitted him to obtain a smaller, less costly storage unit. Other utilities maintained flexibility with storage unit charging times by promising to provide a specified number of kilowatt-hours over a one-day period. With this flexibility, users contributing to nighttime peaks were shifted to the daytime period.

Ripple control was practical from a technical point of view, but it did raise some questions about the justification of off-peak rates. In particular, storage space heating customers enjoying low rates for this service were contributing to system peak demands. The utility had to either provide additional capacity or invest in control equipment to shift the loads. Neither of these costs was recovered through the rates offered.

Ripple control was often introduced as a load management procedure to shave load peaks caused by another load management procedure--storage heating. This is not unlike the present situation in parts of the United States where air conditioning was promoted by the utilities to fill summer load valleys. As air conditioning became widely accepted, annual load factors continued to improve until the new summer peak became greater than the winter peak. Currently, United States utilities are considering load management (or direct load control) as a way to shave the air conditioning peak.

3.5.1 Load Scheduling

Flexibility was achieved in utility systems where both time-switch and ripple based systems were used. It was not necessary to replace all time switches to achieve flexibility. These two types of controls complemented each other; one was a forward controller and the other a backward controller.

Time switches were forward controllers in the sense that they turned on at the beginning of the off-peak period and stayed on until the storage unit reached the desired temperature. Most storage heating units under time-switch control turned on at about the same time, but turned off at different times depending on the electrical and thermal capacities of the system and the thermal energy previously depleted. The result was a large initial storage heating load which dropped off gradually at the end of the off-peak period. Attempts to stagger time switch on-times somewhat relieved the situation. However, the on-times remained at an early time to allow enough charging time for worst-case individual conditions.

Ripple-based receivers were used as backward controllers; their on-times were staggered; the receivers were turned on as late as possible in the off-peak period to permit full charging of the storage unit. The on-times varied from day to day depending on the previous day's weather

(energy depletion) and on the next day's weather forecast (energy requirements). When forward and backward controllers were used together, the load on one picked up as the other dropped off so that a reasonably level load was achieved.

3.5.2 Contribution to Reserve Requirements

A portion of the load, subject to ripple control, contributed to a utility's generating reserves. With ripple control, load could be turned off almost instantly. Although storage heating loads were large, they occurred in most utilities when overall loads were below the peak value and ample reserves were available. In this case, the reserve potential of storage heating was not important.

On the other hand, when daily load shapes during the peak season were nearly flat, storage heating did provide an important reserve. Thus, storage heating customers became off-peak interruptible customers. Most utilities, however, preferred and encouraged interruptible industrial loads. Industrial load peaks typically coincided with system peak loads, so that the greatest deferrable load existed when it was likely to be most needed. No special communications were necessary for an interruptible load because customers had under-frequency relays or were asked by telephone to drop load.

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Chapter 4

ECONOMICS OF LOAD MANAGEMENT

4.1 INTRODUCTION

The decision to adopt a specific load management strategy is not just an economic one: environmental, political, and sociological factors make the quantitative cost/benefit analysis of alternative load management strategies a difficult undertaking. Not surprisingly, such comprehensive studies have never been performed in the United States or Europe; even strictly economic analyses have been incomplete in their scope.

This chapter describes some economic factors considered in evaluations of load management in Europe. These factors provide a point of departure for the development of a more comprehensive economic assessment. Since no two economic analyses studied used exactly the same procedure, the findings reported here represent the approach typically taken in Europe. The results given below are displayed in the form of algebraic equations for conciseness; the equations are not necessarily adequate for use in an economic assessment of utilities in the United States. Furthermore, in attempting to summarize the approach of several different companies the equations consider more factors than were treated by any single analysis studied.

Economic evaluations from the utility and the customer perspective were performed in Europe. Similarly, separate economic studies were performed for peak shaving and for valley filling. In principle, any load management practice should simultaneously benefit both the utility and the customers.

4.2 THE UTILITY PERSPECTIVE

4.2.1 Peak Shaving

Peak shaving was economically attractive to electric utilities whenever the benefits anticipated were greater than the perceived costs, or when

$$\Delta C_{GTD} + \Delta U > C_{LM} + \Delta R \quad (1)$$

where

ΔC_{GTD} = annual cost savings in generation, transmission and distribution due to capacity deferments (\$/kW-yr)

ΔU = annual savings in production costs (\$/kW-yr)

C_{LM} = annual costs for load management facilities (\$/kW-yr)

ΔR = annual losses in gross revenue (\$/kW-yr)

Each of these terms is described below.

Capacity Cost (ΔC_{GTD}). The capital cost of installing additional peaking capacity was estimated by adding together the average cost of generating capacity required to serve the peak demand shaved, and the cost of associated additional transmission and distribution capacity.

Thus,

$$C_{GTD} = C_G + C_{TD}$$

where

C_G = annual cost of peak generation (\$/kW-yr)

C_{TD} = average annual cost of transmission and distribution capacity (\$/kW-yr)

The annual capital investment cost was calculated from the total investment cost (\$/yr) multiplied by the capital recovery factor. The capital recovery factor, a , is the ratio of yearly payment to total investment cost and was calculated from the annual interest rate, i , and the amortization period, n , using

$$a = i[1 - (1+i)^{-n}]^{-1}.$$

The value of the capital recovery factor varied with the specified equipment involved.

Table 4.1 gives data, obtained from publications authored by equipment suppliers, for three typical applications. This table also illustrates the range of values used [1-3].

Table 4.1
CAPACITY COST DATA

Quantity		Source		
		[1]	[2]	[3]
	Cost of generation (\$/kW)	171.50	300	} 570-820
	Cost of transmission and distribution (\$/kW)	228.50	100	
i	Interest (% per year)	7	-	-
n	Amortization period (yr)	30	-	-
a	Capital recovery factor	.0806	-	-
C_{GTD}	Annual cost of capacity (\$/kW/yr)	32.23	-	-

Control Costs (C_{LM}). The capital costs for implementing a load control technology were calculated as:

$$C_{LM} = (C_c + NC_m)/NAP, \quad (2)$$

where

C_c = initial total annual communication cost (\$/yr)

N = number of customers using the control

C_m = unit annual cost of receivers (\$/yr)

ΔP = average diversified peak power reduction per customer (kW)

Communications costs were defined to include the utility controller and the signal transmission system. Similarly, the receiver cost includes local signal receivers, actuators, and metering apparatus.

In Europe, ripple control was used for centralized load control. The cost of communication equipment increased with the voltage level, the transformer capacity at the injection point and the number of receivers served. The cost per receiver depended on the type of receiver and other factors such as installation cost. It was estimated that the diversified demand for storage water heaters in Europe was 1.1 kilowatt [4] and up to three or four kilowatts for storage space heaters in cold climates [4]. Table 4.2 gives data, obtained from publications authorized by equipment suppliers, for three typical applications and illustrates the range of values used [1-3].

Production Cost Savings (ΔU). Production cost savings were calculated as:

$$\Delta U = (u_p - u_v)h \quad (3)$$

Table 4.2
RIPPLE CONTROL COST DATA

Quantity		Source		
		[1]	[2]	[3]
	Cost of injection unit (\$)	25,650	$3.300 \times 10^{6**}$	} 500,000
	Cost of receiver (\$)	46,600	86.67**	
N	Number of receivers	2000	50,000	5000
ΔP	Diversified demand (kW)	0.60***	.75***	2-3
	Control cost per unit of power saved (\$/kW)	97.38	204.45	50-33
i	Interest (% per year)	7	-	-
n	Amortization period (yr)	20	-	-
a	Capital recovery factor (1/year)	.0944	-	-
C_{LM}	Annual cost of ripple control (\$/kW/yr)	9.31*	-	-

*Includes \$0.114 for maintenance

**Includes 33 percent installation cost

***Water Heaters only

where

u_p = peak period marginal production cost (\$/kWhr)

u_v = off-peak marginal production cost (\$/kWhr)

h = number of hours per year during which load was shifted (hr/yr)

The marginal cost of off-peak production included only fuel costs since all of the capital equipment costs were attributed to the peak period customers.

Revenue Losses (ΔR). Revenue losses were determined using:

$$\Delta R = (r_p - r_v)h \quad (4)$$

where

r_p = peak period energy rate (\$/kWhr)

r_v = off-peak energy rate (\$/kWhr)

4.2.1 Overall Analysis of Peak Shaving

A minimum value for the off-peak energy rate was obtained by substituting equations (2), (3) and (4) into equation (1) and solving for r_v :

$$r_v(\min) \equiv r_p - (u_p - u_v) + [(C_c + NC_m)/NAP - \Delta C_{GTD}]/h \quad (5)$$

For off-peak rates below this value, the utility revenues did not recover the costs of load control service. In practice, no case was identified where all factors were considered in this manner.

Most commonly, production costs and revenue impacts were neglected. The above equation became a simple comparison between the capital costs of control and the additional generation peaking capacity. The equation, as shown, was incomplete; the effects of energy losses and maintenance costs, for example, were not included. When the data of Tables 4.1 and 4.2 were compared, the cost of generating capacity was determined to be from two to twenty-five times as great as the cost of control. This calculation, which ignored the effects on production cost and revenues, was the central argument made by promoters of ripple control. The electric utilities themselves, agree with this calculation. There were minor variations in the details but the scope of the comparison was the same; some authors also considered growth rates in water heater consumption and saturation [1] while others included maintenance in the annual costs [2].

4.2.3 Valley Filling

The utilities evaluated valley filling from equation (5) by deleting the capital cost and the peak-period production cost and energy rate. Thus:

$$r_v(\text{min}) = u_v + (C_c + NC_m)/N\Delta Ph \quad (6)$$

In practice, for both peak shaving and valley filling, the marginal peak and off-peak production costs were based on values existing prior to the addition of load management. No utility incorporated the changes in cost values determined by the generation mix evolving from changes in the load. Furthermore, no utility included the costs of additional base load capacity needed to satisfy increased off-peak loads.

Many European electric utilities initially considered the benefits of valley filling to be so obvious that no comprehensive analyses appear to have been performed and none are reported in the literature.

4.3 THE CUSTOMER PERSPECTIVE

4.3.1 Valley Filling

Storage space and water heating were the most important factors involved in peak shaving and valley filling in Europe. From the customer's perspective, storage heating was attractive when annual energy savings were greater than annual costs for storage heating equipment. When electric storage heating replaced the direct burning of natural gas or oil:

$$C_f > C_s \quad (7)$$

where,

C_f = annual costs for fossil heating (\$/yr)

C_s = annual costs for storage electric heating (\$/yr)

Electric storage heating costs were calculated as the sum of capital and operating costs:

$$C_s = C_{sh} Q_s + r_v q_s \quad (8)$$

where,

C_{sh} = annual cost of storage heating equipment (\$/kW-yr)

Q_s = storage heating electrical capacity (kW)

q_s = annual electric energy consumption for the service (kWhr/yr)

The storage heating electric capacity was usually adequate to provide the thermal load on the coldest day of the year after a charging time of about eight to twelve hours.

Natural gas or oil heating costs were calculated similarly using

$$C_f = C_{fh}Q_f + r_fq_f \quad (9)$$

where,

C_{fh} = annual cost of fossil fuel heating equipment (\$/MBTU-yr)

Q_f = thermal capacity (MBTU)

r_f = fuel energy rate (\$/MBTU)

q_f = annual heating fuel consumption (MBTU/yr)

For comparison with electric service, 1 MBTU is equivalent to 293 kW/hr, ignoring the approximately 80 percent efficiency of direct burning.

4.3.2 Overall Analysis of Valley Filling

A maximum value for the off-peak electric energy rate acceptable to the customer was obtained by substituting equations (8) and (9) in equation (7) and solving for the off-peak electric rate:

$$r_v(\max) \equiv (r_fq_f + C_{fh}Q_f - C_{sh}Q_s)/q_s \quad (10)$$

For electric rates above this value, customers found fossil fuel heating more attractive than electric storage heating.

Table 4.3 gives a range of costs for direct electric and storage electric heaters. The data collected here is from many different countries and years. To make costs as comparable as possible, monetary values were converted to U.S. dollars at the conversion rate existing at the time that the reference was published, and then inflated to the level of

the 1975 U.S. dollar. In most cases, the data were not intended as a precise evaluation, but rather as illustrative of the costs and savings possible.

Table 4.3
ELECTRIC HEATING CAPITAL COSTS

Item	Cost (\$/kW)	Source
Direct heater, controls and installation	55	[10]
	56	[11]
	68	[12]
	142	[13]
Storage heater, controls and installation	110	[14]
	126	[10]
	133	[15]
	184	[13]

Cost data varies widely, but the ranges in Table 4.3 suggest that capital costs for storage heating were about three to five times as great as those for direct heating.

Many European electric utilities now offer mixed direct and storage space heating service. The concept of mixed heating was based on the fact that a substantial portion of the heating capacity was needed for only a small portion of the year [9]. Just as it was cost effective for a utility to satisfy peak power requirements with inexpensive peaking generators using relatively expensive fuel, so it was also cost effective for customers to use direct heating to meet peak space heating requirements. Heating load duration curves, shown in Figure 4.1a, were used to determine the balance between storage and direct electric space heating. The point of intersection of the unit cost curves in Figure 4.1b defines the optimum mix; when the duration of use was greater than that corresponding to the point of intersection, it was economical to use storage heating.

Figure 4.1

HEATING LOAD DURATION AND UNIT COST CURVES

4.3.3 Peak Shaving

A similar result to equation (10) was obtained for peak shaving when an existing peak electric load was converted to off-peak electric storage heating. Direct heating costs C_e (\$/year) were calculated using:

$$C_e = C_{eh}Q_e + r_e q_e \quad (11)$$

where terms have the same definitions as those used in equation (9). When equations (8) and (11) were compared it was found that:

$$r_v(\text{max}) = (r_e q_e + C_{eh}Q_e - C_{sh}Q_s)/q_s \quad (12)$$

For off-peak electric rates above this value, customers found direct electric heating more attractive than electric storage heating.

In practice this sort of analysis was generally carefully computed, and it is apparent that customers did realize personal economic savings by adopting storage heating.

4.4 RATES

4.4.1 Rate Structures

In many cases, European electric utility tariff structures were complex. The consumer often had the choice of several maximum demand levels, single or dual-rate metering, as well as other features. Representative rates for electric space heating are shown in Table 4.4. The data presented indicates that the ratio of peak to off-peak rates was about two to one, independent of country.

Table 4.4
PEAK AND OFF-PEAK RATES IN REPRESENTATIVE
EUROPEAN COUNTRIES

Country	Monthly Fee (1975 US \$)	Peak Rate (mills/kWh)	Off-Peak Rate (mills/kWh)	Source
France	8.70 (12kW max)	28.7	13.1	[16]
	13.04 (18kW max)	28.1	13.1	[16]
Belgium	4.18	63.7	34.3	[5]
United Kingdom	1.58	29.3	13.3*	[17]
		29.3	12.0**	[17]
West Germany		32.2	12.9	[18]

*13.3 hours storage heating recharging period.

**12.0 hour storage heating recharging period.

4.4.2 Rate Determination

When the actual storage heating rate charged customers was

$$r_v(\min) < r_v < r_v(\max),$$

then the storage heating service was beneficial to both the utility and to the storage heating customer and did not penalize the non-storage customer.

However, there are indications that electric utilities established their off-peak energy rates to attract natural gas and oil heating customers to electric services. This was done by setting the electric energy rate below the maximum energy rate ($r_v(\max)$) acceptable to customers without proper regard for the minimum value derived using utility economics. The maximum and minimum values depended, of course, on specific local generation and load characteristics.

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Chapter 5

EFFECTS OF LOAD MANAGEMENT

5.1 EUROPEAN UTILITY LOAD CHARACTERISTICS

5.1.1 Daily Load Characteristics

Figure 5.1 shows the load curves of various European countries. The curves are all for typical winter days on utility systems exhibiting winter peaks. Daily load factors are lower during the summer period. The curves are for 1969; load management implementations have increased daily load factors for some utilities since that time.

The European countries tend to have both a morning and evening peak occurring at approximately 8 a.m. and 6 p.m. respectively. However, for several countries, most notably Great Britain, West Germany and the Scandinavian countries, midday valleys are almost nonexistent; their daily load curves tend to be flat with the only significant valley occurring around 3 a.m. These fairly flat load curves are the results of customer load management techniques. The Norwegian curve, for example, shows a high load factor due to the aluminum industry taking advantage of vast hydro resources. Other countries, like West Germany, attribute high load factors in part to the large industries which maintain round-the-clock production. The curves shown are load curves and thus do not exhibit the impact of pumped hydro storage or interchange agreements.

Daily load factors have been calculated by the authors using the load curves of Figure 5.1. The results are included in Table 5.1. Daily load factors in Europe during the winter heating period, when these factors are highest, are typically in the range of 75 to 85 percent.

Figure 5.1
EUROPEAN LOAD CURVES
1969 WINTER DAY

Figure 5.1 (continued)
EUROPEAN LOAD CURVES
1969 WINTER DAY

Figure 5.2

HAMBURG ELECTRIC WORKS [1]
 DAILY LOAD CURVE
 TYPICAL JANUARY DAY

Significantly higher daily load factors do exist in some countries. For example, the 1973 data of Figure 5.2 for Hamburg, West Germany, represents a value of 95 percent [1]. The figure shows the evolution of daily load factor from 1968 to 1973, indicating that load management was heavily promoted until 1973.

5.1.2 Annual Load Characteristics

Storage heating and other customer load management techniques did not shift demand from one season to another. Load management strategies principally affected the daily load factors, not the annual ones.

Table 5.2 shows annual load factors for the nine countries of the European Economic Community [2]. Load values range between 57 and 68 percent for 1974 (except for Luxemburg which had an annual load factor of 83 percent).

5.1.3 U.S. Load Factors

For comparison, U.S. utilities have an average annual system load factor of 61 percent [3].

Daily load factors and annual load factors for 22 representative U.S. electric utilities are shown in Table 5.3. The daily load factors average 82 percent.

5.2 GENERATION CHARACTERISTICS

Table 5.4 shows the structure of the power generation capacity in the original six Common Market countries (Belgium, France, Germany, Italy, Luxemburg, Netherlands). From the data for 1975, it is clear that conventional thermal units (gas, oil and coal fired units) provide

Table 5.1
DAILY LOAD FACTORS 1969
(Winter Peak Season)

Country	Daily Load Factor (percent)
Belgium	84
Denmark	72
France	82
Ireland	76
Italy	77
Netherlands	78
United Kingdom	82
West Germany	80

Table 5.2
ANNUAL LOAD FACTORS 1974

Country	Annual Load Factor (percent)
Belgium	67
Denmark	55
France	68
Ireland	57
Italy	64
Luxemburg	82
Netherlands	62
United Kingdom	53
West Germany	63

Table 5.3
DAILY AND ANNUAL LOAD FACTORS OF 22
REPRESENTATIVE US ELECTRIC UTILITIES

Utility	Daily System Load Factor, 1975 Peak Period (percent)	Annual System Load Factor, 1975 (percent)
1	79	55
2	81	60
3	78	60
4	87	77
5	81	54
6	81	57
7	79	47
8	89	65
9	78	58
10	80	62
11	81	62
12	78	66
13	86	62
14	80	52
15	79	51
16	85	57
17	82	62
18	85	67
19	80	66
20	81	62
21	78	56
22	88	66
Average	82	60

Table 5.4

POWER GENERATING CAPACITY [6]
(European Economic Community)

	1970		1975		1980	
	1000 MW	%	1000 MW	%	1000 MW	%
Total	144.1	100	203.7	100	321.6	100
Hydro-Electric	36.3	25.2	42.5	20.9	58.8	16.7
Run-of-the-River Plant	12.9	9.0	13.7	6.7	15.1	4.7
Storage Plant	23.4	16.2	28.8	14.2	38.7	12.0
Geothermal	0.4	0.3	0.4	0.2	0.4	0.1
Conventional Thermal	104.0	72.2	148.0	72.7	205.5	63.9
Nuclear	3.4	2.3	12.7	6.2	61.9	19.2

most of the electricity in Europe. However, European projections predict that 50 percent of the new capacity developed between 1978-1980 will be nuclear. Pumped storage capacities are also increasing, from six percent of new capacities in 1975-1977, to ten percent in 1978-1980. The proportions of all other types of new capacity are shown as decreasing in these two time periods [4,5].

Because of their high daily load factors, European utilities are adding efficient base load units (such as nuclear plants) to their existing generation capacity. One measure of the desirable level of base load capacity is the ratio of the daily minimum demand to the daily peak demand; a higher minimum to peak ratio means more base load units can be justified. In Belgium, for example, the ratio of daily winter minimum to the daily peak was 58 percent in 1960. By 1970 it had risen to 63.2 percent, and by 1974 it was 74 percent.

In West Germany the ratio of the minimum to the peak was 45 percent in 1960. By 1970 it was about 60 percent, and in the last few years it has risen to about 70 percent.

Load factors, generation mix, and ratio of minimum to peak demands were secondary indicators of the success of load management in Europe. These indicators are typically presented because they are available or can be readily computed from existing data. The primary measures--capital requirements and utility financial health--are not publically available. Because of the difficulty in correlating utility activities, no one, including the utilities, understands the direct relationship between load management and long-term utility finances.

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