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Discussion Series on PURPA Related Topics

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City Utilities of Springfield, Missouri
Springfield, Missouri
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The statements, findings and conclusions are the responsibility of the authors and do not necessarily reflect or state those of the Department of Energy, City Utilities of Springfield, or those who have contributed data to this report.

ABSTRACT

Experimentation with load management was part of several Projects. Seven specific techniques are examined in this report: energy storage systems, end-use improvement (insulation), interlocks, timers, ripple systems, radio systems and controlled voltage reduction.

Energy storage systems were tried in two Projects. They were found to be capable of deferring loads to off-peak times, but in one of the Projects the installation cost was too high for economical use and in the other customers were reluctant to purchase the units. These systems required a lot of customer involvement and the disruptions in a household due to installation seem to have discouraged homeowners from accepting the incentives offered for their installation.

Interlocking devices were tested in the North Carolina Project. There were no equipment problems and there was some evidence that customers were able to save by using them. However, so few devices were installed that reliable data was lacking. Consequently no conclusions were drawn regarding the feasibility of the interlocking devices.

The insulation and weatherization programs of Seattle City Light and City Utilities of Springfield are examined in this report. Both of these Projects had extensive insulation programs. Seattle's program included financing by the utility and quality control inspections for customers. The financing program was considered very successful and it is to be extended with even more favorable terms. Springfield's program included energy audits and information to customers on energy savings due to insulation as well as information about insulation contractors.

A ripple system to control hot water heaters was tried in Vermont. Four Projects used radio signals to control various appliances such as irrigation pumps, air conditioners and hot water heaters. Both radio and ripple systems involve installing a control on the customer's appliance, and consequently involve some common problems. Educational efforts especially for air conditioner servicepersons and electricians are important in establishing and maintaining customer and utility confidence in the switches. All of the systems were able to reduce loads during peak times, but one problem which had to be solved was that of "rebound" when the control time expired.

Controlled voltage reduction was tried in California. This technique involves an adjustment in local feeder voltage regulation practices. Current procedures in setting these voltages reflect past economic conditions, when fuel costs for generating electricity were much lower. By reducing voltage to the low end of the range the energy requirement of most electrical appliances is reduced without affecting their use. Savings resulting from voltage reductions in the Pacific Gas and Electric test were 635 million kwh's. The cost of implementing the reductions was $138,000.

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THE DISCUSSION SERIES ON PURPA RELATED TOPICS

The Discussion Series on PURPA Related Topics is composed of five volumes: Metering, Billing, Information to Customers, Load Management Techniques and Master Metering. These reports are based on twenty-five Demonstration and Implementation projects sponsored and directed during the past five years by the U.S. Department of Energy, Office of Utility Systems. Each of the topics bears directly on one or more of the federal standards contained in the Public Utilities Regulatory Policies Act of 1978 (PURPA). This volume, Load Management Techniques, relates primarily to the Time-of-Day rates standard, PURPA IB(d)3. The experiences related in this report deal, in part, with the procedures and equipment which are affected when time-of-day rates are implemented.

One goal of these reports is to describe how people in a variety of settings have dealt with the many practical issues in each topic area. Another is to highlight the lessons and summarize the experiences of the Project participants. These reports do not stand as systems manuals or provide prescriptive guidelines on how to deal with these topics. Rather they offer an account for those charged with the responsibility of implementing PURPA requirements to learn from the insights and problems which occurred during the Rate Demonstration projects.

This series of reports will be useful to utility and regulatory people in judging the full scope of work related to these topics, anticipating problems and planning the spectrum of requisite activities.

CHAPTER ONE : INTRODUCTION

The DOE sponsored Electric Rate Demonstration Projects (Projects) were more than elasticity measurements, demand projections, usage figures, and statistical analyses. Behind each table and graph in the Project reports are experiences in planning and implementation of work which has been ongoing in each Project for several years. This fourth report on Load Management looks at the many field experiences in the Projects dealing with demonstrating how customers respond to Time-of-Use (TOU) rates.

This volume is not an engineer's or economist's manual, but an account of field activities involving many aspects of the selection and operation of load management techniques. The purpose here is to synthesize the experiences and highlight patterns and anomalies with specific examples. By so doing it is hoped that the uninitiated will have the opportunity to participate in the experiences of others before themselves engaging in work with time differentiated load management equipment.

A number of electric utilities and public service commissions will soon become involved for the first time in the implementation of the PURPA standard on Time-of-Day rates, IB(d)1; this report is primarily for their use. Information contained here, however, may also be useful to manufacturers and consultants. They will have the opportunity to assess Project accounts of field experiences, providing a viewpoint which may ultimately aid in design and the preparation of installation and operating procedures.

Large volumes of data, daily logs, field reports and other documentation from the Projects serve as a source of information for this report. Review of these files led to the basic design of the report. Follow-up interviews with Project personnel provided the detail and richness of first-hand experience.

Four general observations stand out in this report:

- Almost all of the techniques tested were able to shift or reduce usage.
- The most successful technique in terms of dollar and kwh savings was the controlled voltage reduction program in California.
- Some of the techniques, such as hydronic storage systems, were economically unsuccessful. One reason was the high installation cost. These costs will probably decline as more familiarity with the equipment is acquired.
- Customer response was generally favorable. Most customers were willing to have certain appliances interrupted in exchange for a lower rate.

CHAPTER TWO : AN OVERVIEW OF LOAD MANAGEMENT TECHNIQUES

INTRODUCTION

This chapter presents an overview of the Projects' work on load management. Only seven of the Projects had experiences with load management equipment. This chapter begins with a sketch of the load management techniques tested in the Projects, describing the techniques involved and the applications of these techniques. A discussion of the Projects' experiences in planning, acquisition and installation follows, and the chapter concludes with an examination of the costs of each technique and an analysis of the results. Savings effected by load management and customer reactions to the process are also featured.

TYPES OF LOAD MANAGEMENT

The Projects and load management techniques discussed in this report are shown in Table 1. These techniques can be broadly categorized as either customer or utility activated, though the two are not in opposition, since both customer and utility participation is necessary in nearly any load management technique. The techniques categorized as customer activated are energy storage systems, end-use improvements and interlocking devices and timers. Those categorized as utility activated are ripple systems, radio systems and controlled voltage reduction.

Vermont and Ohio conducted tests of hydronic hot water storage systems. This technique involved installing insulated water tanks and heating elements in new homes to provide heat. The basic principle of the system is to heat water and use it for space heating. Water was heated during off peak hours and stored in the tank for use in peak times. During off peak times the system operated like a normal heating system. Both Projects established a special interruptible rate for the hydronic systems.

The Arizona Project tried an energy recapture system which might be classified as an energy storage technique. Escaping heat

TABLE 1

Load Management Techniques Used in
the Demonstration and Pilot Implementation Projects

Project	Technique	End Use Controlled
Arizona[a]	Radio Signal Heat recycling	Air conditioning Hot water
Arkansas[b]	Radio Signal	Air conditioning and irrigation
California[c]	Voltage Reduction Radio Signal Time switches Two way powerline Ripple[k] system	All uses Air conditioning Water heater Swimming pools air conditioning
Grand River[d] Dam Authority	Aerial Thermography Insulation	Space heating and cooling
New Jersey[e]	Automatic Meter Reading[l] and load management system	All uses
North Carolina[f]	Interlocking Devices	Primary and Secondary appliances
Ohio[g]	Radio Signal Hydronic Energy Storage System	Air conditioning Space heating Hot water
Seattle[h]	Insulation	Space heating and cooling
Springfield[i]	Aerial Thermography Insulation	Space heating and cooling
Vermont[j]	Ripple System Hydronic Energy Storage System	Hot water Space heating

Source: [a]Arizona Final Report, February 1978 and telephone interview, Paul Hart, Arizona Public Service Company, August 1980.

[b]Telehone interview, David Bryant, Arkansas Power and Light, November 1980.

[c]A Second Year Report to the Department of Energy, Californi Energy Commission, May 1979.

(continued)

[d]Telephone interview, Jerry Taylor, Grand River Dam Authority, August 1980.

[e]New Jersey, Final Report, August 1978.

[f]Telephone interview, Billy J. Yarborough, Carolina Power and Light, November 1980.

[g]Ohio Final Report, Volume I, January 1977, and Quarterly Progress Report, June 1976.

[h]Seattle City Light, Quarterly Progress Report, March 1979.

[i]Telephone interview, Cathleen F. Meyer, City Utilities of Springfield, Missouri, August 1980.

[j]Vermont Progress Reports, July - September, 1975 and March 1976.

[k]Did not reach full operational stage.

[l]Project was terminated in 1978 and the system was not operational as of December 1980.

from air conditioners was captured and used to preheat water before it entered the hot water heater. This experiment was limited in scope, but successful.

Some kinds of end use improvements were common in most of the Projects, but only home insulation will be examined in this report. A number of Projects had some kind of home insulation program, but Seattle City Light and City Utilities of Springfield, Missouri, had unique features in their programs. In most Projects, home insulation information was distributed to customers. Seattle and Springfield distributed two types of information which were unique: information about insulation contractors and information about insulation financing programs. Both Projects attempted to alert customers to installation standards. Springfield conducted an aerial thermography program and an energy audit program to show customers how well or poorly their homes were insulated. Seattle City Light attempted its own financing program for home insulation.

The North Carolina Demonstration Project conducted experiments with Load Limiting Devices. These are commonly called interlock devices and are used to prevent simultaneous use of major appliances. These devices are wired in series with a prime load so that a secondary load is disconnected when the prime load is turned on. Some devices allow three appliances to be interlocked. It should be noted that interlocking devices provide no direct benefits to customers unless there is a demand charge in the rate or a special rebate for those who agree to use the devices. Carolina Power and Light, one of the participating utilities, had a demand charge component built into one of its experimental TOU rates.[1]

Vermont experimented with a one way ripple system, designed to send a voltage ripple from a transmitter through distribution lines to a receiver attached to a specific appliance in the home. The ripple switched the appliances off during specified periods (peak) and on during other periods (off peak). In Vermont the system was used only for hot water heaters. They had planned to

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[1]Telephone interview, Billy J. Yarborough, Carolina Power and Light, November, 1980.

use it for the hydronic storage system but were unable to implement the test, which had logistic problems.[2]

Radio signal devices were used in four Projects. This technique consists of erecting a transmitting tower and installing receivers on hot water heaters, air conditioners or other appliances. A wave signal is transmitted from the tower to the receiver which then turns the switch on or off. In some systems the signal turns the appliance off and a pre-set timer turns it back on.

One load management technique which did not directly involve customers was a controlled voltage reduction program. This technique, used in California by Pacific Gas and Electric, involved reductions of the minimum and maximum voltage levels delivered to residential customers.[3] Regulation of voltages in local power supplies reflected a time when the cost of generating power was lower. It was economically rational to reduce the cost of local voltage regulation by setting local voltages at or near the upper limits, to insure an adequate voltage at all times and to all customers, rather than make efforts to control voltage levels more closely.

The voltage reduction often accompanied gross reductions in voltage from control generating facilities, to reduce demand during periods of oversupply. Sometimes a system of rotating blackouts was used as an alternative. Both measures were extreme actions, taken only in crisis situations. With the increasing cost of electrical power generation it was thought that greater efforts to improve regulation of voltage levels were more economical, and that reducing voltage for conservation on local feeders could avoid inconvenience to customers.

Some of the other Pilot Implementation Projects had experience with load management techniques. The Springfield Pilot

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[2]Telephone interview, Charles Elliott, Green Mountain Power Corp., November, 1980.

[3]Telephone interview, Steve Reynolds, Pacific Gas and Electric, August, 1980.

Project used appliance meters to demonstrate to customers the usage of various appliances. The utility purchased 100 appliance meter which cost about $15 each, and loaned them at no charge to their customers. This appliance metering preceded further planned load management techniques.[4] In the Connecticut Pilot Project two of the participating utilities were moving toward load management technologies. In June, 1979 United Illuminating decided to acquire bi-directional control equipment. Requests for proposals to vendors were released in mid 1979 and proposals were received in the fourth quarter of 1979. Northeast Utilities decided to use magnetic tape recording meters for its load research program.[5] Each of these techniques is more thoroughly examined in Chapters 3 and 4.

PLANNING, ACQUISITION AND INSTALLATION EXPERIENCES

Most of the Projects underwent planning periods before selecting the techniques and equipment to be used in their tests. In some of the Projects this planning consisted of contacting vendors to give presentations on equipment capabilities and cost. In the Arkansas Project vendors gave presentations to the participating utility. They examined four ripple systems and two radio systems. One of the radio systems was chosen, with lower cost the major factor in the choice.[6]

In Vermont the participating utility was committed to the "use of proven" equipment. Once they decided to control hot water heaters, they conducted a survey of control systems. This survey revealed that two-way systems were only in the prototype stage. The utility decided to use a one-way system which had been proven in Europe over a period of time. The major problem was not in choosing the system, but in locating customers who were willing to buy a hydronic energy system in the area served by the substation

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[4]Springfield Pilot Implementation Project, Quarterly Report, January-March, 1978.

[5]Connecticut Pilot Implementation Project, Quarterly Report, April-June, 1979.

[6]Telephone interview, David Bryant, Arkansas Power and Light, November, 1980.

where the system was installed. Green Mountain Power originally had planned to control five of its ten hydronic units with the ripple system. Since customers could not be found all ten had to be controlled with timers. The ripple system was used only to control hot water heaters.[7]

The Arizona Demonstration Project and the North Carolina Pilot Project engaged in a rather extensive planning and selection process. The Arizona Public Service Company conducted a study to find the most acceptable equipment. Six communications systems were considered: Table 2 gives an evaluation matrix for the six systems considered for the Project. Pilot wire and leased line systems were not considered in depth due to the expense involved and the installation time required. The other four methods, power line carrier, radio transceiver, radio receiver and auto-dial telephone were examined at greater length.[8]

In addition to the capabilities and attributes listed in the table the utility also considered:

- Frequency and duration of signal
- Number of devices which could be addressed
- Operating temperature ranges for the central and remote equipment
- Capability for double pole switching to satisfy local electrical codes
- Battery back-up
- Overall cost of equipment regarding both purchase and lease.[9]

Each system was considered in terms of installation, practicality, and cost. Only two of the systems--power line carriers (ripple control) and radio receivers--were considered to be practical. The other systems were either not established or were under trial. Largely on the basis of cost, a Motorola Radio System was selected.[10]

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[7] Vermont Demonstration Project Progress Report, July-September, 1975.

[8] Arizona Demonstration Project, Final Report, February, 1977.

[9] Ibid.

[10] Ibid.

TABLE 2

Evaluation Matrix Used in Selecting Load Control Equipment, Arizona Demonstration Project

Capabilities & attributes	Power Line Carrier	Pilot Wire	Leased Lines	Radio Transceiver	Radio Receiver	Auto-Dial Telephone
At Least 3 Switching (Multiple)	Yes	Westinghouse	No	READEX Electronics Inc. No	Motorola No	Darco Telemetering Systems No
Positive action	No	No	No	No	Yes	No
Effect Measurement	No					
AMR	No	Yes	Yes	Yes	No	Yes
TOD metering	Yes - as switching	Yes	Yes	Yes	No	Yes
State of development	Ripple control well established	Under trial	Under trial	Not established	Well established	Not established
Remote License Required	No	No	No	Yes	No	No
Loss of Power action	Save state as when power went off	Save state as when lost pwr.	NA	NA	NA	NA
Total system Address	25 channels - 'ON' functions		$>1 \times 10^6$	$>1 \times 10^6$	$>1 \times 10^6$	$>1 \times 10^6$
Group Address	Normal		>750	Not at present	11	>750
Individual Address	No		9999	Yes	No	9999
Installation a) Time-calendar	12 months typically	Not established	Not established	Not established	4 months delivery	Not established
b) labor	15 install. 1 day 1 man	"	"	"	4 hours	"
c) cost	Not known	"	"	"	\$72	"
Customer Over-ride	Can provide - not normal	No	No	No	No	No
Physical Size of Signal generator	See literature	See literature	Not established	Small-size of VHF transmtr.	Small-size of VHF transmtr.	Not established
Time to control (Master controller)	Static 15 seconds Rotary 1 minute	Not known	20 second max.	1 second max.	1 second max.	20 sec. max.
Self contained switching (Remote)	Yes	No	No	No	Yes	No
Power Requirements a) Main	415V line-line 50 KVA @ 50% of time	Not known	Not known	150 watts approx.	150 watts	Not established
b) Repeater	NA	"	NA	150 watts apprx.	150 watts	--
c) Remote	Filter circuit	"	Not known	20 watts approx.	1 watt	Not estbl.

Source: Arizona Demonstration Project, Final Report, February 1978.

Review and selection of hardware took about four and one-half months. Requesting bids took about a month and a half. Nearly six and a half months were spent in ordering and receiving the equipment. Some equipment arrived early, and installation actually began about half way through this period. In fact, installation took a little more than three months (since it was started early, it was actually completed within a month after the arrival of all of the equipment). During this time the installation procedure was also planned and scheduled and the software was designed. It was almost 13 months from the start of the selection process to the completion of the installation. This was just a few days off the original schedule. As a result of sound planning and scheduling it was possible to begin data collection during the month of July and continue it through September.[11]

Once the system was selected it was decided to use a new all-electric subdivision for the test. Ninety-six units were selected for the test and an air conditioning dealer was subcontracted to install the receivers on the homes. The customers were offered free service inspection on their air conditioners and a guarantee that it would be restored to its pre-test condition if it was damaged by the test.[12]

The North Carolina Project considered several strategies for load management.[13] Planning began with a search of the literature on load management, and other utilities were contacted. One of the participating consulting firms, ICF, Inc., ranked the various strategies,[14] using criteria that had been established by the

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[11] Ibid.

[12] The local manufacturer and distributor of the systems in the subdivision was informed about the nature of the test to insure that customers' warranties would not be invalidated by the test. This same company was hired to install the switches and inspect the units before the test.

[13] The North Carolina Demonstration Project tested interlocking devices. This is discussed in Chapter 3.

[14] North Carolina Pilot Project Progress Report, January, 1978.

Project team.[15] The criteria for selecting load management strategies were:

- Hardware availability
- Cost of hardware and installation
- Expected magnitude of effects on system load patterns
- Availability of load management as a reliability device
- Time required for implementation
- Anticipated effects on generation mix
- Effect on system peak
- Immediate effects on utility revenues
- Required customer education
- Anticipated customer acceptance[16]

The strategies were initially divided into three categories: 1) utility controlled devices, 2) automatic load control devices and 3) customer controlled load management devices. However, these classifications were altered somewhat when more clearly defined priorities emphasized investment strategies and gave more certainty to load pattern changes. The load management strategies were then divided as follows:

I. Customer Side Alternatives--Strategies that could be implemented without utility equipment investments
   A. Advertising campaigns to gain increased conservation
   B. Incentive rates
      1. Reduced rates for residences meeting insulation standards
      2. Special rates for solar energy backup services
      3. Load factor-related demand plus energy rates
      4. Controlled water heater rates (customer buys control)

II. Company Side--Physical Load Management--Strategies which might require equipment investment
   A. Direct utility control of residential or commercial water heaters, air conditioners, etc.

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[15] The Project included the North Carolina Utilities Commission, Research Triangle Institute, ICF, Carolina Power and Light and Duke Power Co.

[16] North Carolina Pilot Project Progress Report, January, 197

B. Interruptible rates

C. Automatic load control--temperature controlled cycling of air conditioners, etc.

III. Company Side--Pricing--Strategies which required metering equipment investment

A. Time-of-day rate

B. Other forms of time-of-use pricing

C. Residential demand and energy rates[17]

The first two categories were selected for preliminary analysis. However, there was a significant overlap of the advertising campaign with other aspects of the Project. Consequently, the preliminary analysis consisted largely of examining incentive rates and company side physical load management.

As a result of an order from the North Carolina Utilities Commission, a program to control hot water heaters was initiated in mid 1980 in the Raleigh area. It was decided to use a radio control system for this test. This system had been used for about two years in South Carolina. There had been some problems with the radio system. Sometimes the signal did not reach a house because it was blocked by a neighbor's house or because the house was below the horizon of the transmitting tower. However, by 1980 the reception rate was estimated to be above 90 percent.[18]

In the Raleigh area test only hot water heaters were controlled. The implementation schedule called for 5,000 installations the first year (1980), 10,000 the next and so on until the service area was covered. Preliminary tests were run on 120 randomly selected houses on which magnetic tape meters were installed. One channel of the meter was dedicated to monitoring the hot water heater. This test was designed to provide solid data on the number of transmissions that actually were received. This would provide the first actual data available to the Projects on signal reception rate. At this writing, the meters were not yet

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[17] North Carolina Pilot Project, *op. cit.*

[18] Yarborough, *op. cit.*

installed so no data exist on the rate of successful signal reception.[19]

In the North Carolina Project air conditioning was not controlled. It was felt that there would be little gain, since the utilities' peaks were fairly well balanced between winter and summer. Also, only central air conditioning systems could be controlled and the saturation of these systems was relatively low.[20]

Special rates for customers who installed interlocking devices, time controls for water heaters, or weather sensitive air conditioning controls were not implemented. To be effective these uses would have to be TOU metered because in the absence of such metering customers could disconnect or by pass the controls. This was considered a major implementation problem.[21]

Acquisition and Installation

The Projects' acquisition and installation experiences varied considerably. A significant cause of this variation was whether the equipment selected was "off-the-shelf" or "state of the art." Using "off-the-shelf" equipment involved little delay, if any, while there were extended delays when "state of the art" equipment was selected. Table 3 lists some of the delays in selected Projects, as well as the length of these delays.

Vermont chose an off-the-shelf ripple system which had been used in European countries for years. There was a short delay in receiving the equipment from the vendor, and another in making final installations, but the system was installed and commissioned within one to two months of the original schedule.[22]

Ohio had some delays in the installation of the hydronic storage units it tested. Most of the delay was due to contractors'

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[19] Ibid.

[20] North Carolina Pilot Project Progress Report, April, 1978.

[21] Ibid.

[22] Vermont Demonstration Project Progress Report, March 4, 197

TABLE 3

Acquisition and Installation Delays
in Selected Projects

Project	Length of Delay	Reason for Delay
Arkansas[a]	2 months	Repair of Delivered Goods
California[b]	6 weeks	Vendor Delivery
New Jersey[c]	3+ years	Acquisition delays due to incomplete development
Ohio[d]	3 months	Technical Installation Problems - hydronic system
Vermont[e]	2-3 months - hydronic system 1 month - Ripple System	Vendor delay and lack of customer purchases Installation

Source: [a]Telephone interview, George Brazil, Arkansas Power and Light, December 1980.

[b]California Energy Commission, "A Second Year Report to the Department of Energy", May 1979.

[c]New Jersey, Final Report, August 1978.

[d]Ohio, Final Report, Volume I, September 1977.

[e]Vermont, Progress Report, September - December, 1975.

lack of familiarity with the system, while in some cases they lacked the proper tools. Lack of familiarity with the system slowed the installation process by several months and required considerable Project personnel time supervising the contractors.[23]

The New Jersey Project experimented with an automatic meter reading (ARMR) system which was (potentially) capable of automatically controlling all consumption of electricity in the house. The Project's experience with this system was one of long and repeated delays, and false starts often occurred, since there were new engineering devices.

The main components of the ARMR system were 1) a single minicomputer called the Delta Dispatch Computer (DDC), 2) six Substation Control Units (SCU's) located, as the name implies, at distribution substations, and 3) 1,000 transponders, each attached to a metering point.[24] The DDC provided overall control of the system for meter reading, load research data collection, and load shedding. It was connected to the SCU's by telephone lines. The SCU's received commands from the DDC and relayed data back to it over these lines. The SCU's relayed commands to the transponders, and received data from them, over the distribution lines. Communication between the SCU's and the transponders was by high frequency signals superimposed on the 60 Hz. AC, a method known as "power line carrier" (PLC). The transponders were selectively responsive to commands from the SCU's; they could transmit back consumption or demand data, or they could interrupt service to suitably connected appliances. Block commands from the SCU's could affect any desired subset of the transponders; thus complex load shedding operations were as feasible as simple ones.

Besides these three major components, the ARMR system used

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[23] Ohio Demonstration Project, Final Report, Volume I, September, 1977.

[24] New Jersey Demonstration Project, Final Report, August, 1978. The following description of ARMR system components is also based on this source.

capacitor isolators,[25] less complex components which were inserted between the SCU's and the transponders. Capacitor isolators were necessary to get the high frequency PLC signals around power-factor-correcting capacitor banks in the distribution system so as to avoid signal attenuation.

A lot of time and effort was spent getting the components of the ARMR system manufactured, then in getting them into working order, and proper functional connection with each other. No component went from design to manufacture to correct functioning without delay: defects, design errors, mismatches, etc., cropped up in every case, after initial installation and testing. Despite the preplanning that went into this phase of the New Jersey Project, trial and error quickly became the main method of implementation.

The specification of the hardware for the DDC was completed in August, 1975.[26] Yet it was not until August, 1978, that the final version of the software package replaced the pilot software used for testing.[27] In the meantime, the DDC underwent a reconfiguration and was upgraded twice to improve its memory capacity.[28] As early as January, 1976, it was clear that the DDC would be delivered too late for scheduled installation.[29] The software required extensive debugging.[30]

Three years elapsed between the planning phase of the SCU configuration and the completion of its last modification.[31] More

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[25] Ibid.

[26] New Jersey Demonstration Project Monthly Progress Report, August, 1975.

[27] New Jersey Demonstration Project, Final Report, August, 1978.

[28] New Jersey Demonstration Project Status Report, March 19, 1976, and Monthly Progress Report, April, 1978.

[29] New Jersey Demonstration Project Monthly Progress Report, June, 1976.

[30] New Jersey Demonstration Project Monthly Progress Report, June, 1978.

[31] New Jersey Demonstration Project Monthly Progress Report, September, 1975, and Final Report, August, 1978.

than a year after the initial planning, during which time a prototype had been built,[32] it was found that changes in the design of the load survey component were required.[33] Proposals received from candidate manufacturers led to further redesign,[34] and the contract for manufacturing the SCU's was not let until nearly two years after the initial designing.[35] Defective workmanship was found in the first units received and they were returned to the manufacturer.[36] Six SCU's were installed and wired two and one-half years after the designing began.[37] A problem of signal-fading led to further modifications.[38] Then serious malfunctions in the power amplifier section developed, requiring even more modifications.[39]

Planning for the installation of the capacitor isolators began in September, 1975, with a review of the system's circuit maps.[40] The functional requirements of the isolators were not specified until January, 1977.[41] While requests for bids went to isolator manufacturers in February, 1976,[42] numerous design

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[32] New Jersey Demonstration Project Status Report, March 19, 1976.

[33] New Jersey Demonstration Project Monthly Progress Report, November, 1976.

[34] New Jersey Demonstration Project Monthly Progress Reports, March and April, 1977.

[35] New Jersey Demonstration Project Monthly Progress Report, June, 1977.

[36] New Jersey Demonstration Project Monthly Progress Report, November, 1977.

[37] New Jersey Demonstration Project, <u>Final Report</u>, August, 1978.

[38] <u>Ibid</u>.

[39] <u>Ibid</u>.

[40] New Jersey Demonstration Project Monthly Progress Report, September, 1975.

[41] New Jersey Demonstration Project Monthly Progress Report, January, 1977.

[42] New Jersey Demonstration Project Monthly Progress Report, February, 1976.

problems stalled the contract until June, 1977.[43] At that time it was clear that the delivery of isolators would be so late that the system would have to begin operation with the capacitor banks disconnected.[44] The vendor apparently could not perform as required, and a new vendor was chosen.[45] The isolators were modified again in April, 1978, but redesign and testing difficulties slowed down their manufacture.[46] The first prototype isolators passed initial testing in June, 1978, two years and ten months after the planning began.[47]

The utility spent the rest of the Project period trying to obtain working transponders. Perhaps the main reason for this delay was the decision to use large scale integration (LSI) circuiting for the transponder controls rather than off-the-shelf discrete components. This forced complete redevelopment of a system that had been under test in the General Public Utilities service area for four years.[48] Design of the LSI circuitry began in September, 1975.[49] Four years and several redesigns and modifications later, transponders still malfunctioned. The first delivery of operable transponders from the manufacturer did not occur until late April, 1978, only a few months before the DOE withdrew from the Project.[50] As late as May, 1979, a defect in

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[43] New Jersey Demonstration Project Monthly Progress Report, June, 1977.

[44] Ibid.

[45] New Jersey Demonstration Project Quarterly Progress Report, January-March, 1978.

[46] New Jersey Demonstration Project Monthly Progress Report, May, 1978.

[47] New Jersey Demonstration Project Monthly Progress Report, June, 1978.

[48] DOE File Document, Memorandum, Shapiro to File, 31 October, 1975.

[49] New Jersey Demonstration Project Monthly Progress Report, September, 1975.

[50] New Jersey Demonstration Project, Final Report, August, 1978.

the transponders forced their return to the manufacturer.[51]

The New Jersey Project's first goal was to use the ARMR system for automatic meter reading in a TOU rate structure, not as a load control technique.[52] Since the first goal was not reached, the system was never tested as a load control method. Nonetheless, the New Jersey experience with this complex technology has a bearing on load control methods, as virtually every problem encountered would have caused the same delays and expenses for load control.

Apparently implementing such advanced technology is typically slow and troublesome. Carolina Power and Light Company (under an EPRI contract apart from the Projects) has been experimenting with a two-way PLC system for four years, and is only now obtaining the first meter readings from eighteen points out of a possible 600. The system has yet to be applied to load control although all of the functions of the ARMR system are goals of this program.[53]

A similar experience was reported in the California Demonstration Project. In that Project Pacific Gas and Electric ran a 75 unit test of a prototype powerline carrier system that was being developed by General Electric. The prototype tested (AMRC) was a two way load management system of considerable complexity. Many technical problems occurred. Most of them were connected with the developmental status of the equipment, but some of the problems were common to the other powerline carrier systems. Powerline carrier systems were thought to have several disadvantages, compared to radio transmission controls. These disadvantages included:

- more complicated and expensive installation
- problems in mounting units
- individual noise and frequency characteristics for each feeder network

[51] Letter, Grygiel to Johnson, May 7, 1979.

[52] New Jersey Demonstration Project Final Report, 1978.

[53] Yarborough, op. cit.

- noise both generated and propagated by the control signals[54]

The Springfield Pilot Project had an ARMR system on order which took about 9 months to deliver. Once delivered, the system had several problems in attaining operational status. Of 228 transponders ordered, only 180 had been installed by late 1980. The Springfield Project is presently using the 180 transponders in their load survey program, but not for load management.[55]

Projects also experienced delays acquiring radio systems, but in general, these delays did not put them behind their schedules. All radio Projects reviewed were able to acquire the necessary equipment and begin testing without serious difficulty. Acquiring the components of the radio system took between 6 and 18 weeks. Even though the utilities frequently experienced delays longer than 18 weeks, they did not consider such delays extraordinary. The problems experienced were those typical of a mature technology rather than one pushing the state of the art. The high reliability and low maintenance costs of the units once installed are further indications of the proven status of the equipment.

There were however, delays in installation due to defective switches and other parts. In the Arkansas Project in 1977 there were a number of problems with the receiver switches. The vendor inspected 16,000 units on site at AP&L's Little Rock warehouse then, and again in 1978 and 1979. These tests showed a number of problems affecting about 5 percent of the 33,000 switches. Most of the problems were relatively minor, however.

Since the vendor's 1977 tests the quality has so improved that no inspection is now made at the central receiving point. The few defective units received are found by installers, who use a hand

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[54] California Demonstration Project, Load Management Workshop, 1979.

[55] Meyer, op. cit.

held transmitter to check for function and proper code. California's experience was in some ways similar to Arkansas'. A similar spot checking routine found only one inoperative switch out of ten.

Both the Ohio and Vermont Projects had delays with their hydronic storage system. There were short acquisition delays in both Projects but these were not particularly significant. Both Projects did, however, experience installation delays. In Ohio the main reasons for the delays were technical ones. Contractors did not have experience with the systems and made a number of mistakes--such as improper pipe installation--which had to be corrected. In Vermont there were few technical problems. Delays there involved delivery from the vendor and inability to find customers willing to buy the storage systems, even at a subsidized rate.

COSTS

Table 4 provides a summary of the costs of the load management techniques. The energy storage systems used in Vermont and Ohio were the most expensive per point. The average installed cost of the energy storage units in Ohio was $8,472. The uninstalled cost of the system in Vermont was $1,850. It is impossible to make a close comparison between Ohio and Vermont, however, because the units were not the same size and the installation costs were not the same.

The Ripple system used in Vermont cost $101,500. This included 300 receivers in houses and one transreceiver. The transreceiver cost $70,000 installed. The per point cost for the receiver was $105 installed. The per point cost for 300 points was $338. However, the transreceiver had a capacity of 20,000 units. Spreading the cost over this capacity drops the cost per point to about $109.

The interlocking device used in North Carolina cost about $64 apiece installed. This is a 1977 cost and it was estimated to be

TABLE 4

Costs of Load Management Equipment

Project	Technique	Total Cost	Cost Per Point
Arizona[a]	Radio System	$ 51,100	$ 531
	Transmitter	18,100	188
	Installation of Receivers	5,117	53
Arkansas[b]	Radio System	$ 7,500	-
	Receivers	28,500	$90-100
California[c]	Voltage Regulation	$183,000	-
	Radio System	-	-
New Jersey[d]	Automatic Meter Reading and Load Management System	-	$1,000 (est)
North Carolina[e]	Interlock Devices	$ 2,048	$ 64
Ohio[f]	Radio System	-	-
	Hydronic Storage System	$25,418	$8,473
Vermont[g]	Ripple System	$105,100[h]	$ 350
	Hydronic Storage System	18,500[h]	1,850

Source: [a]Arizona, Final Report, February 1978.

[b]Telephone interview, George Brazil, Arkansas Power and Light, December 1980.

[c]Telephone interview, Steve Reynolds, Pacific Gas and Electric, August 1980.

[d]New Jersey, Final Report, August 1978.

[e]Telephone interview, Billy J. Yarborough, Carolina Power and Light, November 1980.

[f]Ohio, Final Report, Volume I, September 1977.

[g]Telephone interview, George Elliott, Green Mountain Power, November 1980.

[h]Does not include installation cost.

about 8 percent higher as of late 1980.[56]

The radio systems used in the Projects cost about $90 to $100 per point, not including the cost of the transmitter or installation and maintenance expenses. The Arizona Project spent about $51,000 dollars for its system. This included equipment costs, and installation of the transmitter and 96 receivers. This expense also included the "in kind" contribution of Arizona Public Service Company. The system in Arkansas cost about $7,500 and each receiver cost about $90 to $100.

The cost of the voltage reduction program for Pacific Gas and Electric in 1979 was $138,000. This cost included the maintenance of transformers and all other equipment involved in the main Phase I program.[57] It was estimated that the cost would increase to $385,000 in 1981.[58]

Costs of the various techniques as well as many other operational aspects are discussed in chapters 3 and 4.

RESULTS

There were mixed results from Project experiences in load management. Most customer response was positive. A majority of the Projects found that customers were willing to shift or interrupt loads. In fact, when the option was available many customers chose to continue load interruption in exchange for reduced rates.

Results from the Projects' experiments with air conditioning controls revealed that most customers suffered no discomfort, nor did they notice changes in home temperatures. Participation in the air conditioner control tests was usually voluntary (though customers with health problems were excluded).

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[56]Yarborough, op. cit.

[57]Telephone interview, Steve Reynolds and Byron Tomilson, Pacific Gas and Electric Co., August, 1980.

[58]Telephone interview, Byron Tomilson, Pacific Gas and Electric Co., December, 1980.

Most Projects were able to reduce peak loads by interrupting power to air conditioners and hot water heaters. Southern California Edison's experience with load leveling devices showed that on hot days the average KW demand per customer was reduced by 1 to 2 KW's: this reduction was sustained during the times of highest demand. Figure 1 shows the demand of customers with and without load leveling devices on two "hot days" in 1976.

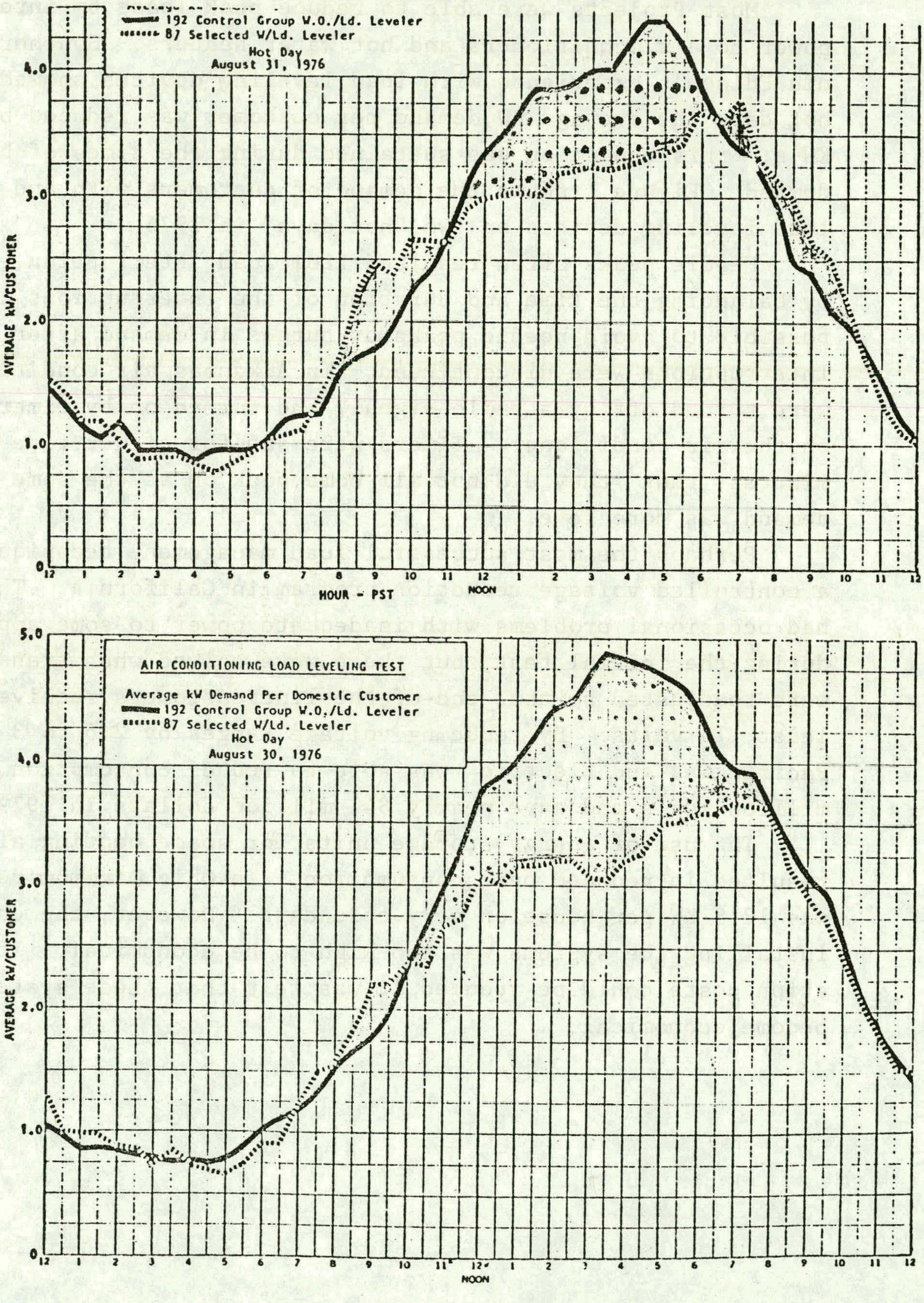
Needle peaks often resulted from load interruption. However, by balancing the time and duration of the interruptions it was possible to avoid needle peaks or surges in demand after the interruptions were discontinued. In Arkansas, air conditioners were turned off by a radio signal, and turned on by timers installed on the air conditioner. Timers were set for either five or nine minutes; thus they did not all come back on at the same time and demand was more level.

Perhaps the most successful load management technique was a controlled voltage reduction program in California. The program had occasional problems with inadequate power to some appliances during the initial test, but these were solved when transformers were readjusted so that end-of-the-line customers received at least 114 volts. By reducing voltage ranges by 2.5 to 3 percent, Pacific Gas and Electric was able to reduce consumption by 635 million kwh's and save nearly $41 million dollars in 1979.

The use of energy storage units for space heating also resulted in reduced peak consumption. In Ohio maximum reduction was 12.8 KW per house on very cold days. However, the cost of installing the systems was too high to be economical. If installation costs could be reduced, it was felt that these systems could become economical.

FIGURE 1

Impact of Air Conditioning Load Test, Southern California Edison, California Demonstration Project



Source: California Energy Commission, <u>A Second Year Report to the Department of Energy</u>, May 1979.

CHAPTER THREE : CUSTOMER LOAD MANAGEMENT TECHNIQUES

INTRODUCTION

This chapter examines three types of load management techniques generally considered to be customer activated: 1) energy storage systems, 2) end-use improvements and 3) interlocking and timing devices. A number of the Projects' experiences with these techniques are examined, including acquisition and installation experiences, costs, and customer response.

The main focus of the examination of energy storage systems and end-use improvement is on home heating, while the section on interlocking devices focuses on appliance usage.

ENERGY STORAGE SYSTEMS

A study of a "low cost" heat storage system was included in the Ohio and Vermont Projects. The studies were conducted by recording and comparing electricity usage of houses equipped with the "storage system" to similar houses without the system. It was thought that the storage system would allow heating loads to be deferred to system off-peak periods.[1]

In Ohio each of three storage homes was equipped with a 1,000 gallon concrete storage tank, a heat pump, a water heater (boiler) and the necessary control devices such as time clocks and temperature sensors. The storage tanks were vented since it was to be a closed system. The use of concrete created a concern about waterproofing, and after consultations with engineers, cement and chemical companies, and university professors, the tanks were waterproofed with a cement base sealant. They were also insulated with two inches of urethane foam.[2] A diagram of the system is shown in Figure 2.

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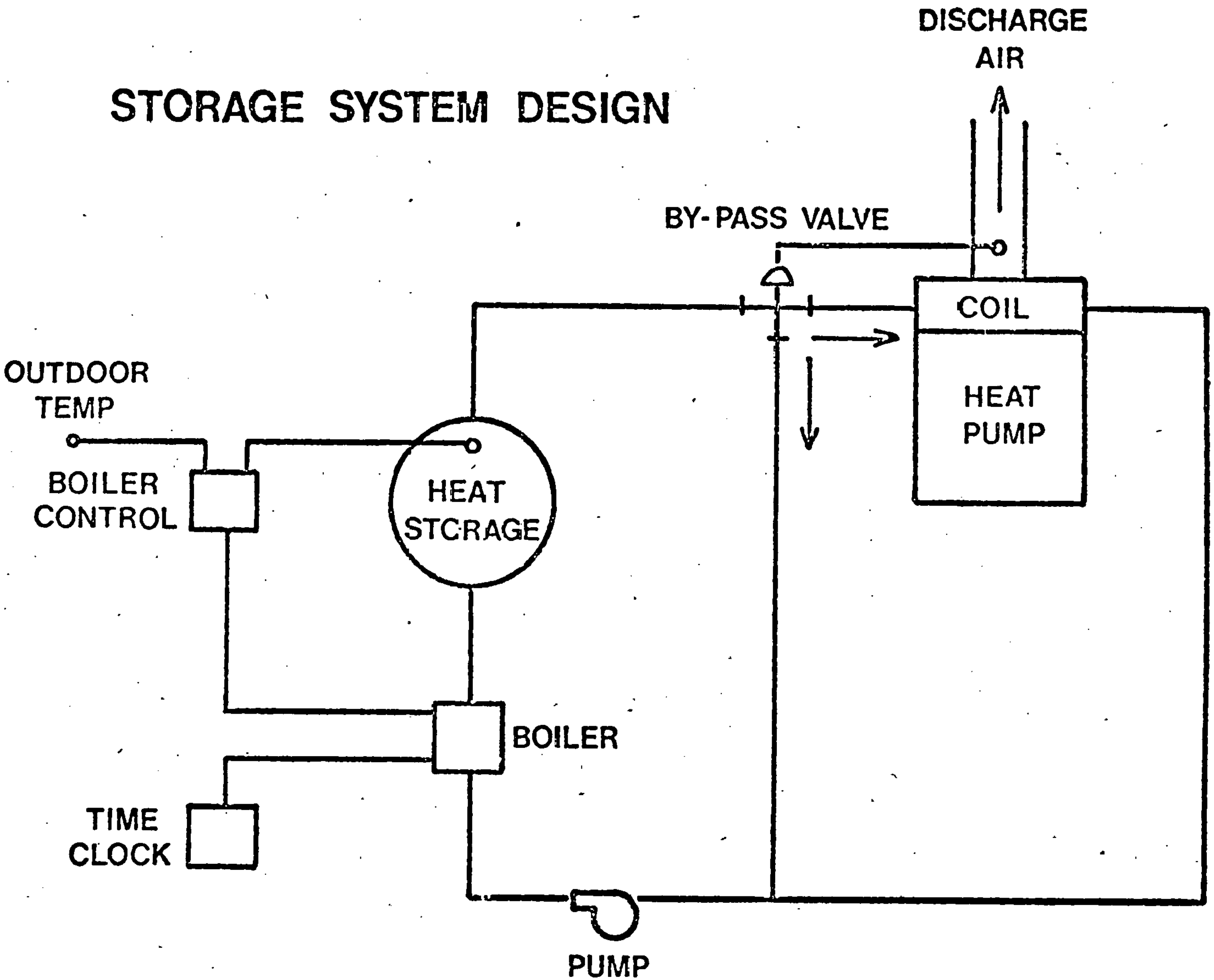
[1] Ohio Demand Management Demonstration Project, Final Report, Volume I, September, 1977.

[2] Ibid.

FIGURE 2

Schematic of the Hydronic Storage System,
Ohio Demonstration Project



Source: Ohio Demonstration Project, Final Report, Volume I, September 1977.

In the Vermont Project ten hydronic new storage units were installed. The heat storage units consisted of a 280 gallon insulated tank, an internal electric heating element and a heat exchanger loop.[3] Originally it was planned that five of the units would be controlled by a ripple system whose cycle could be changed at any time. The other five units were to be controlled by timing devices installed at the residence. The cycles for these units were inflexible and had to be reset in the event of power outages.[4] However, since customers willing to buy the units could not be found in the area served by the ripple system, timers had to be installed in all ten units. The timers had to be able to turn the storage unit off and on twice each day because of the double peak times for Green Mountain Power. That is, the timer had to turn the unit off at 9:00 a.m., on at noon, off at 4:00 p.m. and back on again at 8:00 p.m. The cost of a reliable timer with this flexibility was approximately $100 per unit in 1980.[5]

Cost

The average cost of the Ohio storage system, including installation, was $8,473. Table 5 shows the detailed cost of each of the three systems. (It was thought that these costs were generally higher than other systems due to their experimental nature.) It can be seen by examining this table that even though there was some variance of cost among the categories the costs for each house were similar. These costs do not include expenses incurred by Toledo Edison in the planning, supervision and maintenance of the storage system.

In Vermont each unit cost approximately $1,800 (uninstalled) in 1975 although the price to customers was $600 (installed) due

[3]Telephone interview, Charles Elliott, Green Mountain Power Corp., November, 1980.

[4]Vermont Demonstration Project, Progress Report II, by Green Mountain Power, August 27, 1975.

[5]Elliott, op. cit.

TABLE 5

Cost of the Hydronic Storage System, by House, Ohio Demonstration Project

Cost Factor	House 1	House 2	House 3
Plumbing - Labor and materials	$5,819 (103 man hours)	$6,396 (190 man hours)	$6,135 (107 man hours)
Electrical	$ 353	$ 340	$ 383
Storage Tank			
Tank	$ 379	654	654
Insulation	275		
Waterproofing	635	760	635
Water treatment	20	20	20
Builder	$1,088[a]	$ 95	$ 200
Misc.	$ 50	$ 445	$ -
Total	$8,621	$8,770	$8,027

Source: Ohio Demonstration Project Final Report, September, 1977.

[a] This house was under construction before final drawings were completed. This cost includes the additional costs due to this.

TABLE 6

Hydronic Energy Storage Systems, Size and Cost,
Ohio and Vermont Demonstration Projects

Project	Tank Size	Cost	Installed	Incentive Payment	Year Installed
Ohio	1,000	$1,350[a]	$8,472[a]	$10/mo + maintenance during test	1975
Vermont	280	$1,800	-	50% of installed cost plus special heating rate	1975

Source: Ohio Demonstration Project Final Report, September, 1977, and Telephone interview, Charles Elliott, Green Mountain Power Corporation, November, 1980.

[a] Average for three units.

to the Project subsidy.[6] Table 6 shows a comparison of the costs of the hydronic systems in Ohio and Vermont. This comparison in dicates that the cost of the equipment for the Ohio System was less than in Vermont. The installation cost in Ohio was however, almost 7,000 per unit. This cost was due to many problems encountered in installation. Part of the cost of installation was the large (1,000 gallon) storage tank. In Vermont, the units themselves were about $500 more than in Ohio. While there is not accurate data on installation cost in Vermont, the units were standard size and fit in about the same space as a "normal" furnace. Few, if any, installation problems were reported in Vermont. It is probably safe to conclude that installation cost in Vermont was much less than in Ohio.

Operation Experiences--Problems

In Ohio the planning of the storage tank implementation began with meetings with marketing representatives of Toledo Edison. It was recommended that a meeting with Toledo area builders be held. As a result of the meetings it was agreed that three builders, who each used a different brand of heat pump, would be contracted to participate in the study. The houses in the study were to be two story 1,800-2,300 square feet (2,300-3,000 with basement).[7]

It was also agreed that an incentive payment to the homeowner would be required. Toledo Edison agreed to maintain the storage system and guarantee the heating consumption during the test. However, this required a separate meter for the heating system, installed inside the house. For the inconvenience of having to provide access to the meter reader and maintenance personnel, the homeowner was given a $10 per month payment during the test.[8]

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[6] Ibid.

[7] Ohio, Final Report, op. cit.

[8] Ibid.

The Ohio Project encountered many problems both in installation and operation. Residential contractors and subcontractors were not familiar with the more complex heating system. There were eleven installation contractors, including general, plumbing, and electrical contractors; a significant amount of time was required for supervision of the installation process. Numerous errors were made during installation. For example, in some cases the plumber ran the pipes "exactly" as indicated on the drawings. Sometimes piping was put across filter openings or above or below storage tank levels. This caused a significant amount of additional work. Also there were many occasions when the proper tools or fittings were lacking and this caused much time to be lost. The Project team concluded that there was a need for upgrading the technical skills of contractors for this system to be successful. They also concluded that the system was too complicated and that the controls were either "too exotic" or unnecessary.[9]

There were two types of operational problems in the Ohio Project: one in the controls and sensors, the other with boiler failures. Each storage tank system was equipped with a high water alarm. Occasionally one of the senosrs malfunctioned and caused the alarm to sound unnecessarily (usually late at night). The sensor was apparently sensing vapor in the standpipe. Rather than reworking the plumbing or installing a new sensor, the controls were disconnected. No water level problems occurred in any of the houses.[10]

Two boiler failures occurred: one in house number 3 and one in house number 1. The first failure was due to malfunction of the control relay and the thermostat. These were replaced, but after a period of time, three of the four elements were made inoperative by water leaking from one of the heating elements, which had shorted out. The short appeared to have been caused by calcium

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[9] Ibid.

[10] Ibid.

scale buildup in the elements. Even though the city water had been treated it was still sufficiently hard to cause scale.[11]

Another problem occurred when the flow switch which controlled the movement of water into the boiler malfunctioned and resulted in "boiler lockout." The problem stemmed from improper installation. While the failure of the switch did not impair the safety of the system, it did cause a distortion in the usage data.

One problem which had been expected, crumbling and cracking of the storage tank, did not occur during the test year. No cracking or leaking was found in any of the tanks. The coating on the inside of the tanks was thought to have prevented these problems.

In the Vermont Project there were few operational problems. There were, however, prolonged delays in the delivery and sale of the hydronic (hot water) storage units. Initially they were to have been delivered in July, 1975, and installed by November, 1975. Several problems caused this delay. First, the vendor was late in delivering the units. Second, there was an unwillingness on the part of customers to purchase the units. Third, there was a discussion and disagreement over the rate and over the rate design for the units.

Customer unwillingness to purchase the units was a multi-faceted problem. First there was some difficulty in finding customers with compatible heating systems (forced hot water), who were installing new furnaces. This was further complicated by the fact that some of the customers had to live in a service area that was to be served by the ripple system. This was because one of the tests was a comparison of clock vs. ripple control of the heat storage.[12]

Ten separate customers meeting the criteria could not be found in time to allow the test to be completed on schedule. The

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[11] Ibid.

[12] Vermont Demonstration Project, Progress Report, by Green Mountain Power Corp., May 7, 1975.

utility advertised in local newspapers for customers willing to purchase the system but was still unable to find enough for the test. The selling points to the customers were 1) the cost of the equipment and installation of the hydronic system would be partially subsidized (50 percent), and 2) they would receive a permanent special heating rate from Green Mountain Power.

The problem was solved by selling all ten units to a developer. The units were installed in ten nearly identical houses. However, it was not possible to sell them in the area served by the substation in which the ripple system was installed.[13]

Designing a rate for the storage units was difficult. There were two schools of thought on the rate design: one argued for a rate based on average energy costs, while the other favored an incremental power rate. The incremental rate was the higher of the two. A rate of 1.6¢ per kwh for the storage units had been set but was unacceptable to the Vermont Public Service Board. At one point the rate of 1.9¢ per kwh was being negotiated.[14]

One problem stemmed from the fact that the units were to be permanent installations and, therefore a rate design had to be assured for some period of time before customers could be expected to install such systems. This problem was made more difficult because salesmen from European firms were offering a variety of heat storage units to customers in the service area. This meant that whatever rate was approved had to be available to all who had storage units.[15]

The rate was finally established, through compromise, at 35¢ per KW per month and 1.4¢ per kwh. The hydronic units were 14 KW so the flat KW charge was $4.90. This, added to the 1.4¢ per kwh, worked out to an average for the ten units of about 1.8¢ per kwh.

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[13]Elliott, <u>op. cit</u>.

[14]Vermont Demonstration Project, Quarterly Report, July-September, 1975.

[15]<u>Ibid</u>.

The rate was designed to cover the off peak cost of power.[16] The units were to be specifically metered and would be running during all off peak hours.

With all of the delays, the units were not installed and operational until March 31, 1976, about four months behind schedule. This meant that a heating season had passed and in order to gather data to test the units a time extension was required. The Project was originally scheduled to be completed in June, 1976, but had to be extended through the winter of 1976-77 to get proper data for analysis.[17]

Results

The results of the Ohio study indicated that the storage system was able to shift heating load to off peak times. Figure 3 shows the usage patterns for a storage unit house and a similar house in Ohio on a January day. As can be seen in this figure, there was a marked difference in the peak and off peak usage. However, demand reductions occurred only on very cold days, and the maximum coincident KW reduction was 12.8 KW per house.[18]

Given the average cost of the system of $8,473 per house the cost per KW was $662. The approximate cost of a peaking capacity was $200 per KW. Thus the Project team concluded that the storage system was not economical. It was also found that the system was too large. The heat pumps actually worked better than expected and could heat down to a lower "balance point." This was the main reason the storage tank was found to be oversized.[19]

In Vermont all ten customers have been satisfied with the units. There were very few problems with them after the initial "bugs" were taken care of. Since the initial units were sold two or three more have been sold and installed in the Green

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[16] Elliott, op. cit.

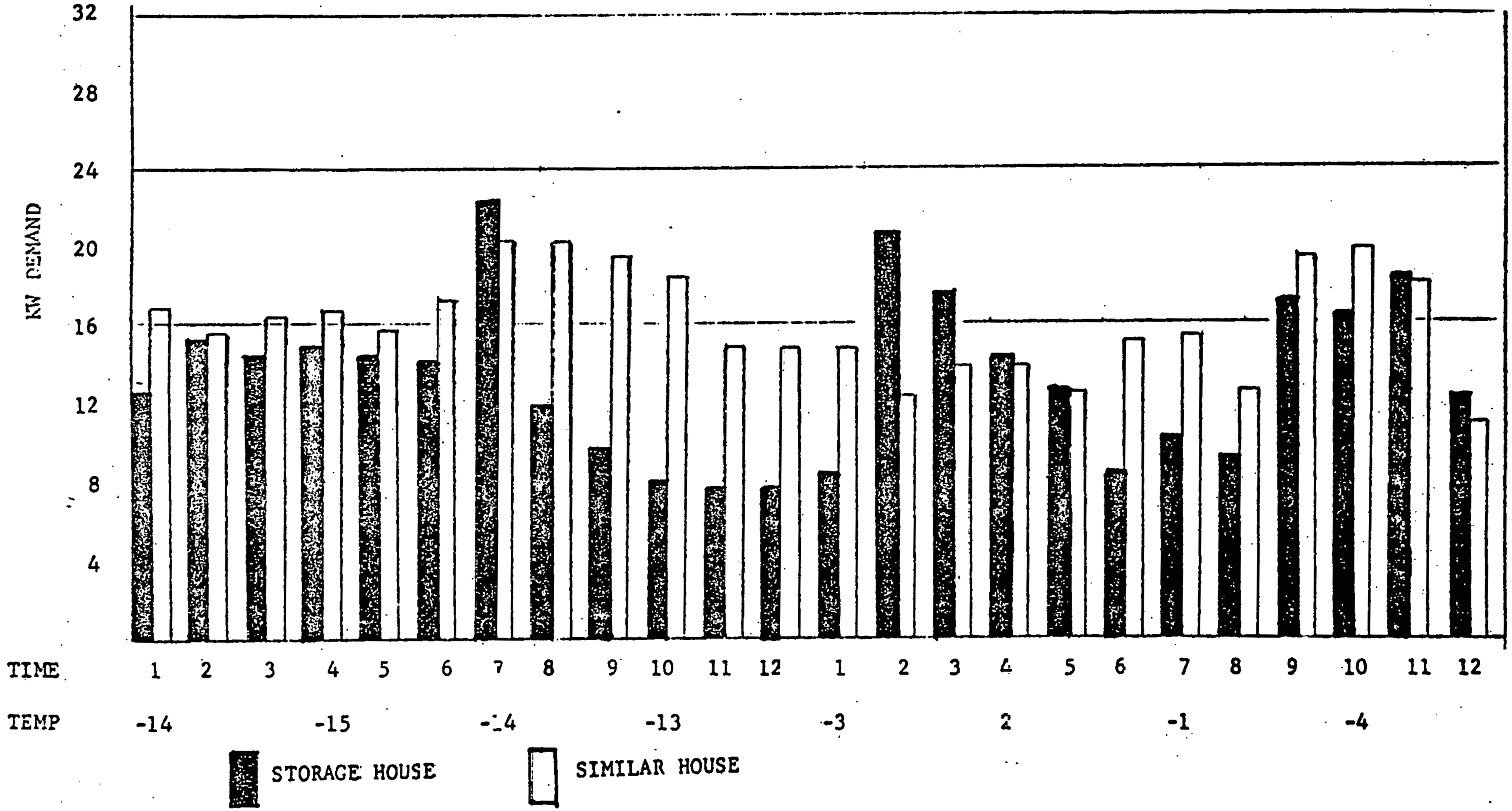
[17] Vermont Demonstration Project, Progress Report IV, by Green Mountain Power Corp., March 4, 1976.

[18] Ohio, Final Report, op. cit.

[19] Ibid.

FIGURE 3

KW Demand of Storage and Similar Houses, by Time-of-Day, January 17, 1977, Ohio Demonstration Project



Source: Ohio Demonstration Project, <u>Final Report</u>, Volume I, September 1977.

Mountain Power service area. However, the relatively higher initial cost of the units has deterred some customers from purchasing them.[20]

One of the factors which determined whether a storage system was able to keep a house heated during peak hours was the energy efficiency of the dwelling. A well insulated house will be more likely to retain heat and therefore requires less from the system. Thus, in part, the success of the storage system was tied to the energy efficiency of the home.

END USE IMPROVEMENT--INSULATION

Several Projects stressed improvement in the overall efficiency of houses. Projects such as the Grand River Dam Authority and City Utilities of Springfield, Missouri, conducted programs to inform customers on the insulation needs of their homes.[21] Both Projects made aerial thermograms of houses in their service areas. These were used to show customers where heat was escaping through the roofs of their homes. Both Projects also conducted other types of energy auditing. Springfield offered customers an extensive audit. The results of the audit were given to customers on a computer printout which rated their house on a scale of A through F. The printout listed specific recommendations to improve the house as well as the potential savings on the fuel bill of each recommendation. Figure 4 is a copy of the printout given to customers.

Two problems were encountered in developing the printout. One problem was making it simple enough for customers to understand yet technical enough to give valid results. This was the reason for the rating system instead of using only heat loss in BTU's. The second problem was trying to compute potential savings without putting the utility "on the spot" but still giving

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[20] Elliott, _op_. _cit_.

[21] The information aspect of these Projects is covered in the _Information to Customers_ report which is part of this series.

FIGURE 4

Sample Computer Printout of the Results of Home Energy Audits, Springfield Pilot Project

ACCOUNT NUMBER 11 22 33333 DATE OF AUDIT 4 1 1978 PAGE 1

NAME TEST HOME-1 STORY ADDRESS HOUSE NO-STREET PHONE NUMBER 111 2222

**** THE FOLLOWING DATA HAS BEEN CALCULATED FROM THE COMPLETED HOME ENERGY AUDIT QUESTIONNAIRE ON YOUR HOUSE.

YOUR HOUSE HAS A CLASS C RATING ACCORDING TO THE FOLLOWING TABLE. THIS IS THE RATING OF YOUR HOUSE FOR ITS HEAT HOLDING ABILITY. THIS DETERMINES HOW MUCH FUEL YOU USE TO HEAT YOUR HOME. THE BETTER INSULATED YOUR HOME IS, THE LOWER YOUR HEATING BILL.

CLASS A	CLASS B	CLASS C	CLASS D	CLASS F
VERY GOOD	GOOD	FAIR	POOR	VERY POOR

SPECIFIC RECOMMENDATIONS TO IMPROVE YOUR HOUSE ARE LISTED BELOW. THESE ARE IN ORDER OF LARGEST POTENTIAL DOLLAR SAVINGS PER YEAR.

			POTENTIAL SAVINGS
1	INSULATE YOUR FLOOR WITH INSULATION WHICH HAS AN R-FACTOR RATING OF R-19.	1	POTENTIAL SAVINGS ON YOUR FUEL BILL COULD RANGE FROM 17 TO 26 DOLLARS PER YEAR.
2	INSTALL INSULATION IN YOUR ATTIC FLOOR OR CEILING WHICH HAS AN R-FACTOR RATING OF R-30.	2	POTENTIAL SAVINGS ON YOUR FUEL BILL COULD RANGE FROM 11 TO 17 DOLLARS PER YEAR.
3	INSTALL CAULKING OR WEATHERSTRIPPING AROUND ALL REMAINING OUTSIDE WINDOWS.	3	POTENTIAL SAVINGS ON YOUR FUEL BILL COULD RANGE FROM 5 TO 7 DOLLARS PER YEAR.
4	INSTALL CAULKING OR WEATHERSTRIPPING AROUND ALL REMAINING OUTSIDE DOORS.	4	POTENTIAL SAVINGS ON YOUR FUEL BILL COULD RANGE FROM 3 TO 5 DOLLARS PER YEAR.
5	INSTALL STORM DOORS ON ALL REMAINING OUTSIDE DOORS.	5	POTENTIAL SAVINGS ON YOUR FUEL BILL COULD RANGE FROM 3 TO 4 DOLLARS PER YEAR.

DURING THE WINTER, TURN YOUR THERMOSTAT DOWN TO 65 DEGREES DURING THE DAYTIME, AND TO 55 DEGREES AT NIGHT

THE POTENTIAL SAVINGS ON YOUR FUEL BILL ARE DETERMINED USING THE FOLLOWING DATA.

1 OUTSIDE TEMPERATURE = 40 DEGREES FAHRENHEIT (AVERAGE HEATING SEASON TEMPERATURE)
2 HEATING SEASON FROM OCTOBER 1 TO MARCH 30 (210 DAYS)
3 CURRENT FUEL PRICES

THE SAVINGS WILL VARY WITH THE SEVERITY OF THE WEATHER, AND THE QUALITY OF CONSTRUCTION AND INSTALLATION OF THE IMPROVEMENTS.

(continued)

FIGURE 4 (continued)

ACCOUNT NUMBER 11 22 33333 DATE OF AUDIT 4 1 1978 PAGE 2

NAME TEST HOME-1 STORY ADDRESS HOUSE NO-STREET PHONE NUMBER 111 2272

**** THIS SHEET GIVES A DETAILED ACCOUNT OF HOW YOUR HOUSE IS LOOSING HEAT.

	HEAT LOSS (BTU/HOUR) WHEN OUTSIDE TEMP. IS 40 DEGREES	HEAT LOSS (BTU/HOUR) WHEN OUTSIDE TEMP. IS 0 DEGREES	PERCENT OF YOUR TOTAL HEAT LOSS
HEAT LOSS THROUGH YOUR WALLS	6982	16838	27
HEAT LOSS THROUGH YOUR FLOORS	6483	15635	25
HEAT LOSS THROUGH YOUR CEILING	4052	9772	16
HEAT LOSS THROUGH YOUR WINDOWS	2774	6690	11
HEAT LOSS AROUND YOUR WINDOWS	2299	5544	9
HEAT LOSS AROUND YOUR DOORS	2210	5330	9
HEAT LOSS THROUGH YOUR DOORS	714	1722	3
	==========	==========	=======
** TOTAL HEAT LOSS (BTU/HOUR)	25514	61531	100
** (PER SQUARE FOOT OF HEATED FLOOR AREA)	18	43 (*)	

YOUR HOUSE RATING (A,B,C,D OR F) IS BASED ON THE TOTAL HEAT LOSS PER SQUARE FOOT (*), AT 0 DEGREES OUTSIDE TEMP.

LOSS/SQ.FT. (*)	00-29	30-39	40-49	50-59	60-
HOUSE RATING	CLASS A VERY GOOD	CLASS B GOOD	CLASS C FAIR	CLASS D POOR	CLASS F VERY POOR

Source: Springfield Pilot Implementation Project, April 1978.

the customers a valid reason for improving the efficiency of their homes.[22] In the first year of the Springfield Project about 825 home audits and 500 infrared camera audits were conducted. This was about 15 percent of the homes in the service area.[23]

Once customers were aware of the condition of their homes they needed information on insulation, insulation contractors and financing. The Springfield and the Seattle City Light Projects both had programs to inform customers in these areas. In fact, Seattle City Light implemented an insulation installation program. Seattle City Light's program explored the facilitation of customer retro-fit insulation by promoting and overseeing independent contractors and financial institutions.[24]

Seattle City Light's program consisted of a four-part program to encourage the upgrading of inadequate insulation. First was a promotional and educational effort to explain the value of retrofit insulation and motivate consumers to enter the program. Second, an "energy checker" performed an inspection of the residence, noting potential savings and explaining what modifications could be made and how they could be accomplished. Third, the customer was referred to a list of participating and qualified contractors screened by the utility. Finally, an inspection was performed by a representative of the utility to insure that the work had been performed adequately.[25] The first two parts of Seattle's program have been discussed in the report on Information to Customers. The last two areas will be discussed below.

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[22] Springfield Pilot Implementation Project, "Explanation of Energy Audit Computer Printout," April, 1978.

[23] Springfield Pilot Implementation Project, "A Brief Summary Report on Conservation Audit Problem Areas," City Utilities of Springfield, Missouri, December 14, 1978.

[24] Seattle City Light Pilot Implementation Project Progress Report, March 31, 1979.

[25] Ibid.

Seattle City Light was primarily interested in facilitating customers' efforts to obtain and install insulation. There appeared to be two areas in which the utility could provide assistance: 1) contractor qualifications and standards and 2) financing. Each of these turned out to be problematical.[26]

Contractor Qualifications and Standards

Participation by contracting firms in the program depended upon the utility's being able to generate enough new business to warrant the firm's time and expense in meeting qualifying standards. Contractors engaged in retrofit and alterations were typically small, independent, owner-managed firms with the owner frequently serving as part of the work force. The market was typified by freedom of entry and exit, a high rate of turnover of firms, and general overcapacity. Consequently the market was characterized by price competition, but not necessarily by uniform quality of the product. Seattle City Light believed it was necessary to establish standards and guarantee that those standards would be attained. This requirement was met by establishing qualifying standards for the contractor, including an agreement signed by the firm stipulating that certain practices would be followed in carrying out insulation installation. A second requirement was that the firm obtain a performance bond and liability insurance, naming Seattle City Light as an insured party.[27]

The least complex of these measures was the requirement for the performance bond. The State of Washington required a $2,000 bond for contractors as a part of its licensing requirements. Seattle City Light thought that this sum was inadequate and required a $5,000 performance bond for contractors participating in the program. Some firms experienced difficulty in obtaining such a bond. Several contractors proposed posting $5,000 in an account upon which they would draw interest but

[26]A Case Study of Seattle City Light's Utility Bank/Contractor insulation program, Brown and Caldwell, September, 1979.

[27]Ibid.

which would be assigned to Seattle City Light as long as the firm was active in the program. This was rejected because of Seattle City Light's opinion that the utility was not authorized to enter into such an agreement.[28]

Since Seattle City Light's insurance coverage began at $500,000, it required participating firms to obtain coverage at that amount. Many firms were already covered at the $500,000 level. Some insurance firms named Seattle City Light as an additionally insured party without cost, others charged 10 percent of the existing premium.[29]

Establishing standards for insulation and for installing insulation proved to be much more difficult. One of the problems was Seattle City Light's inability to carry out the extensive testing required to establish objective standards. Further, many of the criteria in use in national building codes did not have a proveable foundation in materials testing. It was believed that adequate attic ventilation was necessary to avoid water vapor condensation which would destroy the insulating capacity of the materials. Therefore, ventilation was required by the Seattle Building Code, which was derived from the Uniform Building Code, which, in turn, was partly founded on the standards published by the American Society of Heating, Refrigerating, and Air Conditioning Engineers. However, an investigation disclosed no testing basis for this standard. In the absence of standards based on physical tests, Seattle City Light relied on customs and usage.

The contractor's agreement in one place states ". . . the warranty shall provide for: . . . Replacement of defective materials or repair of poor workmanship _as judged by the standards of the industry_."[30] (italics added) Much of the language of this standard agreement appeared to say more than it actually did; for instance, the agreement stated, "Insulation shall not be installed in attics

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[28] _Ibid_.

[29] _Ibid_.

[30] _Ibid_.

without provision for adequate ventilation."[31] The words "without provision for" could have been used as an escape clause, allowing the insulation contractor to avoid the work of installing ventilation by informing the customer of the requirement for ventilation. Customers, not wishing to incur the expense of installing ventilation or seeing holes cut in their roof, and not fully understanding the reason behind the requirement, might have chosen not to have adequate ventilation installed.[32]

There were two routes which might have been used to enforce contractors to adhere to the warranty. The first was a provision in the contract that the contractor must submit any dispute with a customer to binding arbitration by the Better Business Bureau. The second avenue was possible removal of the contractor from the list of firms qualified to participate in the insulation program. A firm could be removed from the program after a reasonable notice, allowing it time to remedy deficiencies.

Financing[33]

Bank participation in the program was minimal. Initially, Seattle banks entered the Project to forestall the development of a utility based financing program, not out of an interest in providing financing.[34]

There were several factors that made weatherization financing unappealing to banks. The size of each individual loan was too small for economical processing. The applicants were not preferred customers and could not be expected to generate follow-up business. The banks proposed the use of bank cards, which would have carried an 18 percent interest rate. Due to inadequate follow-up for the program, it was uncertain whether any bank made any funds available to the program.[35]

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[31] Ibid.

[32] Ibid.

[33] Ibid.

[34] Ibid.

[35] Ibid.

Subsequent to the program, Seattle City Light instituted an Insulation Demonstration Project for residences primarily heated by electrical power. As part of the program Seattle City Light provided financing at 6 percent interest for the entire amount of the work performed and, in addition, offered a 10 percent discount to the customer from the contractor's bill. This program had considerable success. The initial promotional efforts resulted in more requests for participation in the program than could be accommodated.[36]

This program was to be phased out on January 12, 1981 and replaced with an expanded one. In the new program a homeowner will be able to finance up to $5,000 for insulation and weatherization. Seattle City Light will charge no interest and payments will not begin for five years. Then payments will begin and customers will have another five years to repay the loan. The justification for this type of financing arrangement is that conservation reduces KW demand and is cheaper, even at zero interest on a 10 year loan, than the next least costly alternative.[37]

INTERLOCKING AND TIMING DEVICES

The North Carolina Demonstration Project was the only one that experimented with interlocking devices. Sixty of the customers on TOU rates were selected to have a load limiting device installed. These customers were among those who had a demand component as part of their rate. Only 32 of the 60 agreed to have the devices installed. This number was judged by the Project consultant to be too small to provide information about the ability of the devices to affect a customer's load or, the devices' impact on the system load. Consequently, there were no calculations as to the savings of these devices.[38]

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[36] Ibid.

[37] Telephone interview, Mimi Sheridan, Seattle City Light, December, 1980.

[38] Telephone interview, Billy J. Yarborough, Carolina Power and Light Company, November, 1980.

There was, however, operational experience with the devices. Installation and operation turned out to be relatively trouble free. There were no complaints by customers about the 32 installed devices. When the test was completed, 18 to 20 customers chose to leave the device in and remain on the demand rate, even though they had to accept responsibility for repair and maintenance of the device.[39]

The devices were offered to customers during the rate test with the agreement that Carolina Power and Light would provide the device, install it, and maintain it. Carolina Power and Light subcontracted the installation of the device and reported no significant problems. The device sold for about $40 and the avearge installed cost was $64. The installation cost was somewhat inflated because the installations were spread out over the service area.[40]

Since the devices were offered only to those on the rate test, customers moving into or out of the houses included in the test were ineligible for the test. Without the special rate the device was of no benefit to the customer. As long as a customer remained in the residence he was eligible to remain on the rate and use the device. When someone moved into a house which had an interlock they were given the choice of keeping it at no charge, or having it removed. If they chose to keep it they had to agree to take complete responsibility for it.[41] However, since there were no residential demand rates other than the test rates, there was little incentive to keep the interlock.

When the rate experiment was over customers were allowed to keep the device, at no charge, and remain on the demand rate. This meant that the demand recording meter had to stay in place and the customer was billed from that meter. Customers who chose to keep the device were asked to sign a termination form accepting

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[39] Ibid.

[40] Ibid.

[41] Carolina Power and Light Memo from Billy J. Yarborough, to All Primary Special Customer Service Representatives, August 2, 1978.

responsibility for all costs associated with the operation and maintenance of the devices.[42]

Timing devices were used in the California Project in two tests. Both Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) ran a test of the use of timers to control swimming pool filter motors during selected peak hours.

In 1977 PG&E wrote to pool owners in the Sacramento area inviting them to participate in an experiment on load control. The Company requested that customers not run their filter pumps between noon and 7 p.m. A free chemical test kit for pool water was offered as an inducement to participate. Forty-two percent of the pool owners participated in the test. PG&E reported a shift of 7,400 kilowatts to offpeak hours. Total cost of the program was estimated to be $37,250, or $5 per shifted kilowatt.[43]

In 1977, Southern California Edison identified new customers with swimming pools. A utility representative visited residences to explain the load control project to potential customers. Seventy-four percent of the customers contacted agreed to allow the switch to be installed. SCE installed 170 time switches--at no charge to the customers--which shut off the filter pump between noon and 6 p.m. Initial operational experience indicated a shift of 312 kilowatts. By 1978 SCE expected to have switches installed on a third of the swimming pool filter pump motors. At a cost of $11 a kilowatt it was expected that 87,000 kilowatts would be shifted to offpeak hours. The $11 per kilowatt cost included a $5 incentive credited to the customer.[44]

Two possible problems or implications were considered in the Project.

1. Shifting filter pump use to nighttime might in some cases create problems by exceeding community noise regulations, which are stricter at nighttime than during the day.

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[42] Ibid.

[43] California Demonstration Project, Staff Report on Load Management Standards, California Energy Commission, June 5, 1979.

[44] Ibid.

2. Some designs of solar pool heaters use filter pump motors as a power source. As solar pool heaters are expected tc increase in number rapidly, attention to their design was needed to insure that additional peak load was not created unnecessarily.[45]

SCE selected 2,500 out of a population of 250,000 single family residences for an experiment in controlling air conditioning peak load. Two hundred were chosen from this pool for the experiment, and 200 were selected as controls. A monthly incentive payment of $2 per ton per air conditioner was made to participating customers. The average air conditioning capacity per home was 3.5 tons.[46]

Magnetic tape recorders monitored consumption at 15-minute intervals. The controlling devices used were General Electric Load Levelers. Units were triggered by an ambient temperature sensor. The interruption was set for 7.5 to 10 minutes each half hour. Fewer than half (87 of 200) of the units functioned properly. Some units prevented air conditioners from functioning at all. The high incidence of malfunctions made it impossible to draw detailed conclusions from the experiment. Southern California Edison analyzed the experience of the 87 residences in which the switches operated properly. A key finding was a load drop of 1.26 kilowatt per residence on a 100°F day. Customer reaction apparently was favorable: eighty-seven percent felt that $2 per ton of a/c was an adequate incentive for accepting the load leveler switches, though most customers recommended a shorter shut off cycle. Further experimentation was planned to obtain operational experience.[47]

SUMMARY

Three forms of load management were discussed in this chapter: 1) energy storage systems, 2) end use improvements (insulation) and 3) interlocks and timers on appliances.

The heat storage experiments in Ohio and Vermont both used hot water storage, but the units in Ohio were larger, more complex, and costlier to install. Since they were more complex, the

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[45] Ibid.

[46] Ibid

[47] Ibid.

units experienced more installation and operation problems. While the Ohio Project was troubled by contractor errors, lack of necessary tools and fittings, and various malfunctions of the control devices, the Vermont Project encountered difficulties only in timely delivery and sale of the units to utility customers, in establishing a rate design for heat storage customers, and in locating potential heat storage customers in the areas served by the ripple control system. This last goal was not attained and all ten units were sold to a single developer in an area outside the ripple range. The Ohio Project's experience indicated that the cost per KW shifted by their hydronic storage system exceeded the cost per KW of peaking generation capacity. This was primarily due to the high cost of installation.

Insulation and weatherization of homes were the main end use improvements addressed by the Projects. Two Projects surveyed area attic insulation quality by aerial thermography. Home energy audits were more generally used to assess efficiency in the Projects. A major program of insulation and weatherization formed part of the Seattle Pilot Project. A promotional campaign, home energy checks (with insulation/weatherization advice to individual customers), direction to approved insulation contractors, and inspection of contractor's work were the main components of the Seattle program. The Project encountered difficulties in controlling the practices of participating contractors, the main difficulty being the lack of quantitative basis for many industry standards. Banks had little interest in home insulation financing and no interest in weatherization loans, so the municipal utility, Seattle City Light, started its own insulation financing program, lending at 6 percent for all of the work. This operation received more applications than it could handle.

Only the North Carolina Project used appliance interlocks with TOU demand rates. They found them to be trouble free in both installation and operation. However, too few customers accepted these devices for valid inferences to be made about their potential impact.

Timers were used on swimming pool filter motors and air conditioners in California. Substantial savings potential was indicated in the former application, but high malfunction rates in the air conditioner timers prevented accurate assessment of their savings potential.

CHAPTER FOUR : UTILITY LOAD MANAGEMENT TECHNIQUES

INTRODUCTION

This chapter examines three types of load management techniques that may generally be considered to be utility activated: 1) ripple systems, 2) radio systems and 3) voltage regulation. The ripple and radio techniques were used to control a number of different loads including hot water, air conditioning and irrigation pumps. Voltage reduction was an attempt to lower the voltage range for residential customers. Each of these techniques is examined in light of the experiences of the Projects.

RIPPLE SYSTEMS

In the Vermont Project the participating utility, Green Mountain Power, studied one-way, two-way and radio control systems before it decided to purchase a Zellweger Ripple Control System. It was a solid state one-way system that was to be used to control hot water heaters and hydronic energy storage units. Green Mountain Power had a policy of using only proven technology. The two-way systems were primarily designed for automatic meter reading. While they offered load management capability and the advantages of two-way communication they were only readily available in prototype form--new systems with no proven history of reliability.[1] The Zellweger Ripple System, on the other hand, had a history of many years of satisfactory service in other countries.[2]

The decision in the Vermont Project proved to be a good one. The system was acquired and installed with a minimum delay. The system was planned to be operational by November 1, 1975. It was actually commissioned and operational on December 2, 1975. Due

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[1] Vermont Demonstration, Progress Report II, by Green Mountain Power, August 27, 1975.

[2] *Ibid.*

to delays in the installation of meters the ripple system did not reach its full capability until March 21, 1976, but this was not in any way attributable to the ripple system itself.[3]

This is directly opposite of the experience of the New Jersey Project. There an attempt was made to use an Automatic Meter Reading and Load Management system. The design installation and operation had many difficulties and after nearly four years of experimentation the Project was abandoned by the Department of Energy.

Initially the ripple system consisted of a transmitter and 100 receivers. The receivers were installed at the site where the load was to be controlled. The transmitter was installed at a substation and two separate feeder lines from that substation were used to send the signal. It superimposed voice frequency impulses on the distribution network. The impulses, sent at the appropriate times, were carried along the electrical system to the receiver, which made the requisite switching operations.

One feature of the system was that it was designed for parallel injection of the ripple signal into 12.4 KV bus bars. Parallel injection, as opposed to series, had a number of advantages. First, system reliability was not reduced by the addition of more equipment. Second, some equipment could be bypassed, or short circuited, during transmission pauses, thus allowing absorption of interfering voltages around the signed frequency, reducing the possibility of a false signal. Addition of more equipment had a further advantage, since the master controller for the system consisted of plug-in units, which allowed further panels to be installed if the experiment indicated system-wide application to be economical.

The initial system of 100 receivers could receive transmission in random order with a transmission time of 6.6 seconds per command. It was also possible to turn on or off all receivers in a command group at once. The system could be increased to

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[3] _Ibid_.

handle a maximum of 20,000 receivers.[4]

After the ripple system was installed and working Green Mountain Power was sufficiently satisfied with the results, and decided to add another 200 receivers. The receivers were installed and have been operating successfully for four years. The Green Mountain Power ripple operated at 12.4 KV for the signal injection, which was considered "uncommonly low." Green Mountain Power felt that this level better suited its residential distribution system and they wanted to find out if a low voltage injection was viable.[5] It was hoped that lower voltage injection would be more economical. There was a risk in testing the low voltage system: if it was not sufficient for the load, a new one would be necessary, since it was not possible simply to increase voltage. The experiment proved to be successful: there were no problems with low voltage injection.

The total installed cost of the ripple system was $101,500, including the injection system at the substation, which had an installed cost of $70,000. Each receiver cost about $105; approximately $15 of this amount was installation cost. The total installed cost of the 300 receivers was $31,500.[6]

The ripple system operated very well in interrupting the hot water load of the 300 customers. There were very few problems. On one or two occasions the operator forgot to turn the heater back on. This of course caused an inconvenience to some customers until the error was detected, but customers reacted favorably to the system.

About half of the customers did not change their consumption habits as a result of the interruptible rate and control of hot water by the ripple system. However, the rest had to change their habits because of a lack of hot water. Some customers who had

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[4]Ibid.

[5]Ibid.

[6]Telephone interview, Charles Elliott, Green Mountain Power Crop., November, 1980.

done large amounts of laundry during peak times had to switch to off-peak, or change to cold water washing. It was also discovere that customers with smaller hot water tanks had to adjust by occasionally deferring laundry, as was the case for large families. However, almost all customers with tanks larger than 40 gallons seemed to have no problems. Most problems concerning lack of hot water were easily solved when members of the family became more conscious of the amount used and the time of consumption.[7]

The hot water interruption test in Vermont was voluntary. Each customer in the test was assigned an interruptible rate of $5.75 per month and informed of the times the interruptions would occur. In Vermont's case they were for 8 hours per day during morning and late afternoon peak periods. Customer satisfaction with the system was so great that all 300 customers have been content to continue with it voluntarily at least through 1980.[8]

RADIO SYSTEMS

Four of the projects, Arizona, Arkansas, California, and Ohio used radio systems to control specific appliances. All four used these systems to control air conditioning, and the systems were used to control irrigation pumps in Arkansas, and hot water heaters in California and Ohio.

There was considerable divergence in types of experimentation among the four Projects. Arkansas's project was quickly followed by a system wide implementation, with 15,000 units installed per year. Other Projects, though sometimes far more sophisticated than Arkansas', have not been followed by such rapid implementation. Some investigators have raised questions concerning the necessity of experimental projects and the economic justification for them. Some suggested that operational experience might just as well be gained in small scale pilot programs. It was

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[7] Ibid.

[8] Ibid.

also suggested that load management technology was changing rapidly and it might be unwise to have large investments in equipment that could soon become obsolete.[9]

All Projects were able to acquire, install and begin operational testing of their systems without serious problems. Available components of radio systems were all mature products. Reliability was good, and maintenance costs were relatively low. Customer acceptance of the modifications involved in the installation of the switches was generally favorable, and while no extraordinary skill or tooling was required for installation, a hand held transmitter proved necessary to verify operation and proper coding of installed units.

False triggering of the receiver switches occurred in some instances, but the non-essential character of the load controlled permitted occasional spurious interruption without harm. The number of available codes in the radio system is not large, but there are several options available for expanding the number of addresses. If no other sources for expanding the capability of the radio system were available, more frequencies could be allocated to utilities for control purposes. It is more likely, however, that the Federal Communications Commission would require that existing technology be exhausted before it would find reallocation of frequencies to be in the public interest.[10] Techniques which might be tested include two tone addressing, digital addressing, and improved bandwidth selectivity, thus allowing closer frequency assignment within the given allocation. All of the techniques would involve increased costs over the units now in service, but since the price of electronic equipment is steadily dropping, this cost should not be excessive.

In the Arkansas Project, Arkansas Power and Light (AP&L)

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[9]Telephone interview, Billy J. Yarborough, Carolina Power and Light Company, November, 1980.

[10]George Sarver, "Presentation to the California Energy Commission Load Management Workshop," in Proceedings Load Management Equipment Workshop, Sacramento, California, September 20-21, 1979.

used a radio signal system to control a portion of its summer peak load. Residential air conditioning and agricultural irrigation pumping loads were selected for central control. AP&L considered four ripple systems and two radio systems. A Motorola radio system was chosen at least partly because it cost approximately half as much as a one-way ripple system.

Motorola model 800w radio control switching units were selected and installed to control a portion of the air conditioning power. The switches were installed by independent air conditioning contractors on the control circuit in such a way that triggering the radio control unit interrupted power to the compressor and outside fan. The inside fan circuit was left unmodified, so the appliance could continue operations. This was to reduce any perceived change in air conditioning. The same switches were also installed to control the irrigation pumps; they were installed in series, using the existing manual control.[11]

The switches were activated by radio transmitted tone signals. Once triggered, the switch initiated a timer circuit which held a relay open, removing power from the unit. The time interval range of values were preset to a 2 minute spread, to smooth load rebound when power was returned to the air conditioning and irrigation pumps.

A Motorola 300 watt transmitter and an antenna were co-located at an already existing AP&L communications tower. Initial tests on the irrigation pumps indicated a range of approximately 45 miles in an area of essentially featureless terrain when the switch was mounted on a pole near the pump motor. Later when other utilities began operating radio transmitters on the frequency, the effective range was much reduced. The radio transmitters broadcast a signal generated by a timer encoder unit. The timer encoder unit sends the signals it generates to the transmitter by way of leased telephone lines.[12]

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[11]Arkansas Demonstration Project, Peak Load Control Study, Arkansas Power and Light Company, October 6, 1975.

[12]Ibid.

Data were recorded on KW magnetic tape recording meters and primary KW recording chart meters. Readings were transmitted by leased telephone lines to AP&L's control center. Twelve of the residences were monitored for inside air temperature. Outside air temperature was recorded at AP&L's Little Rock control center.

No failures were experienced for the encoder, the leased lines, or the transmitter units. Two switch failures occurred during installation and one switch failed during the test period due to a loose cover which allowed rain to enter the radio unit. Normally the failed units were replaced with spares and the defective units were repaired by AP&L's communications shop.[13]

AP&L conducted a peak load control study during the summer of 1975, from June 15 to September 15. The major objectives of the study were:

- To determine the contribution of individual air conditioning units to peak demand and the amount of air conditioning load which could be displaced during the system peak load periods by installing remote control devices to stagger the coincident use of customer air conditioning units.
- To determine the threshold of customer inconvenience incurred by control of customers' air conditioning during peak load periods.
- To determine the most feasible mode of remote control: radio control, carrier signal over Company distribution circuits, leased telephone circuits, time-temperature, etc.
- To determine the loss or gain of energy usage resulting from deferring customers' air conditioning loads to an off-peak period.
- To evaluate this type of control as a means of shedding non-essential load during critical shortages of generation capacity.
- To determine if irrigation load can be diverted from on-peak to off-peak periods by remote control, without preventing the total water quantities required per day from being pumped or causing any ill effects to the crops.[14]

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[13] Ibid.

[14] Ibid., p. 2.

To encourage participation in the study of residential air conditioning, an incentive of $2.00 per ton(of the installed air conditioner) per month was offered, plus a free air conditioning check prior to the test period. A further guarantee was that all customer equipment would be returned to pre-test condition and AP&L assumed responsibility for any damage to customers' equipment due to the test. Out of the 261 residential customers contacted, 218 agreed to participate in the test. A roughly equal number of residences of comparable air conditioning size and comparable structural characteristics were selected to act as a baseline. Consent was obtained from 12 farm customers to install remote control switches on irrigation pumps. No compensation for cooperation was offered.[15]

During the study period, an independent air conditioning firm was contracted to maintain the air conditioners for residences which participated in the control portion of the test. A 24-hour answering service received complaints and notified the air conditioning firm of requests for maintenance. Sixty-seven service calls were received, but none were due to the radio control switches.[16]

Test runs were made on weekdays from June 15 to September 15 from 1:00 p.m. to 5:00 p.m., when ambient air temperature was higher than 85 degrees farenheit. Total load tests were made to determine the size of the total load controlled by all switches simultaneously interrupting the power supplied to the controlled units. Once during each hour of the test all switches were triggered. Total KW on the test circuits was recorded before, during, and after the test. Other variables recorded were time of day, date, temperature, and humidity. To test the operation of the system in its normal peak shaving mode, a roughly equal number of switches were triggered at 4 minute intervals during an hour, except for a reference period when no units were triggered,

[15] Ibid.

[16] Ibid.

to allow a measure of total non-controlled load.[17]

From July 21 to September 15 the twelve irrigation pumps with radio controlled switches were triggered off on weekday afternoons from 1:00 p.m. to 5:00 p.m. when ambient temperature exceeded 85 degrees farenheit. Kwh's were recorded on magnetic tape to confirm that the pumps were actually inoperative during the period.

Irrigation pump users were favorably inclined towards radio actuated load control, especially if off peak rates could be offered as an incentive. Energy costs of irrigation pumping are a significant cost of irrigated farming. Some owners anticipated that occasions might arise in which continuous pumping might be required. The test period was an unusually wet mild summer.[18]

A post-test survey was conducted at the 218 participating residences. Seventy-three percent of the participants responded. Sixty-nine percent of those responding did not sense any change in inside house temperature due to the interruption of air conditioning power. Fifty-eight percent had no objection to the radio control switch, and 12 percent wanted the switch removed.[19]

Following the favorable results obtained in the test period, AP&L began a system wide program of implementation. The planned rate of installation was 15,500 switches per year on residential air conditioners. This rate of installation was to be maintained until all eligible residential air conditioning was subject to load management.

In 1977, AP&L had experienced problems with the first shipment of switches from the vendor. Problems included dirty relay contacts, incorrect wiring, faulty connectors and loose cables. Motorola inspected 16,000 switches that had been shipped at the AP&L warehouse, and replaced defective units. Improved quality control and a redesign of the unit have reduced the number of defects. Currently no inspection is made when the units are received at AP&L's Little Rock warehouse: defective units are

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[17] Ibid.

[18] Ibid.

[19] Ibid.

found when the installers check the units for proper functioning.

With 33,500 switches installed in 1978, AP&L has substantial operational experience with the system. To verify proper operation of the switches a program of inspecting installed switches was initiated in 1978.

Since there was not a routine check system to monitor the functioning of the switches a random check of 790 units was made in 1978. The problems identified in this check resulted in a decision to check an additional 1,557 units in 1979. The results of the inspections are shown in Tables 7 and 8. Table 7 shows the type of problems encountered in the inspections while Table 8 shows the types of problems repaired.

When all residential air conditioners are controlled, it is anticipated that 125 megawatts of new peak generating capacity can be deferred and 500 megawatts of controlled load will be available for immediate emergency load shedding. As an incentive to install switches, the Arkansas Public Service Commission approved a $1.44 credit per KVA of installed air conditioning capacity for each residence during July, August and September. This incentive amounted to $21.60 per season for a customer with 5 KVA air conditioning capacity.

Customers asked to have fewer than 1 percent of the switches removed. The reason usually given was fear that the switch might create problems in the air conditioning unit. Despite AP&L's conducting educational programs for air conditioning contractors, 40 percent of the switches were removed because an air conditioning serviceman advised the customer that the switch would damage the air conditioning unit. AP&L's policy was to pay the cost of service calls and repairs if the switch caused the problem: its expense per customer from problems with switches has been $.06 per customer per year, while operation and maintenance had been budgeted at $5 per customer per year. The capital cost of the system per customer is somewhat less than $100. It is expected that each switch installed will allow peak load to be reduced by one KW. The cost of peaking capacity was estimated by AP&L to be $175 per KW.

TABLE 7

Reasons for Radio Switch Failures
Arkansas Demonstration Project

Problem	1978 Number Found	1978 Percent Found of Those Inspected[a]	1978 Estimated Number Co.-Wide[a]	1979 Number Found	1979 Percent Found of Those Inspected[b]	1979 Estimated Number Co.-Wide[b]
Not at Location Indicated	9	1.14	235	46	2.95	959
No response to Signal	51	6.46	1331	106	6.81	2213
Customer Tampering	13	1.65	340	7	0.45	146
Damaged Switch	4	0.51	105	12	0.77	350
Improper wiring or installation	19	2.41	496	26	1.67	543
Incorrect Nameplate amps	204	25.82	5319	273	17.53	5697

Source: George W. Brazil, "Load Management Through the Radio Control of Air Conditioners", presented at, Load Management Equipment Workshop, California Energy Commission, September 20, 21, 1979, Sacramento, California.

[a]Based on an inspection sample of 790 switches from approximately 20,600 installed.

[b]Based on on inspection sample of 1,557 radio switches from approximately 32,500.

TABLE 8

Types of Problems Found and Repaired on Radio Switches, Arkansas Demonstration Project

Type of Problems Repaired	Number of Problems Repaired[a]	Percent of Total Installed with Problem
Solder Problems	323	0.98
Bad Reed	142	0.43
Bad Transistors	132	0.40
Bad Resistors	40	0.12
Bad Capacitors	20	0.06
Bad Transformer	12	0.04
Bad Relay	4	0.01
Dirty Relay Contacts	454	1.38
Tuning Problems	380	1.16
Replace Cables	49	0.15
Bad Coil	2	0.01
Bad Housing	6	0.02
Bad Reed Socket	1	0.00

Source: George W. Brazil, "Load Management Through the Radio Control of Air Conditioners", presented at, Load Management Equipment Workshop, California Energy Commission, September 20, 21, 1979, Sacramento, California.

[a]Some switches had more than one problem. The total number of switches that had problems repaired as of July 18, 1979 is 1,523. This is 4.55 percent of the 33,500 switches installed as of September 10, 1979. These repairs include problems found during inspection of delivered switches before they were installed.

The Arizona Project also used a radio signaling system to control air conditioners. Generally the equipment was similar to that used in Arkansas. However, Arizona Public Service Company (APS) developed an evaluation matrix which they used in the selection of their system. The matrix is shown in Table 2, which lists the capabilities and attributes of all six systems considered by APS.

Of the control techniques available, pilot wire and leased line systems were eliminated before detailed considerations began, because of the cost and lead time required. Power line carrier (Ripple), radio transceiver, radio receiver, and auto dial telephone methods were each given full consideration. Some of the reasons for purchasing the radio signaling system were 1) its relatively low cost, 2) its reliability and 3) its availability.

The system was available with a four month delivery time. Installation time per unit by an air conditioning contractor was reported to be four hours, at a cost of about $53 per unit.[20] Figure 5 is a simplified schematic of the radio system which APS purchased.

Central control commands are communicated by micro-wave to a radio transmitter located on a mountain top which, in turn, generates radio signal transmissions received by the receiver switches.

Arizona Public Service Company is a summer peaking utility. A large portion of its peaking load is due to residential air conditioning. Control of air conditioning load would allow more efficient use of generating capacity and provide a source of low priority load available for shedding during shortages in generating capacity.

To test the practicality of controlling air conditioning load, a study was conducted from July 26, 1978 to September 10, 1976. The objectives of the study were:

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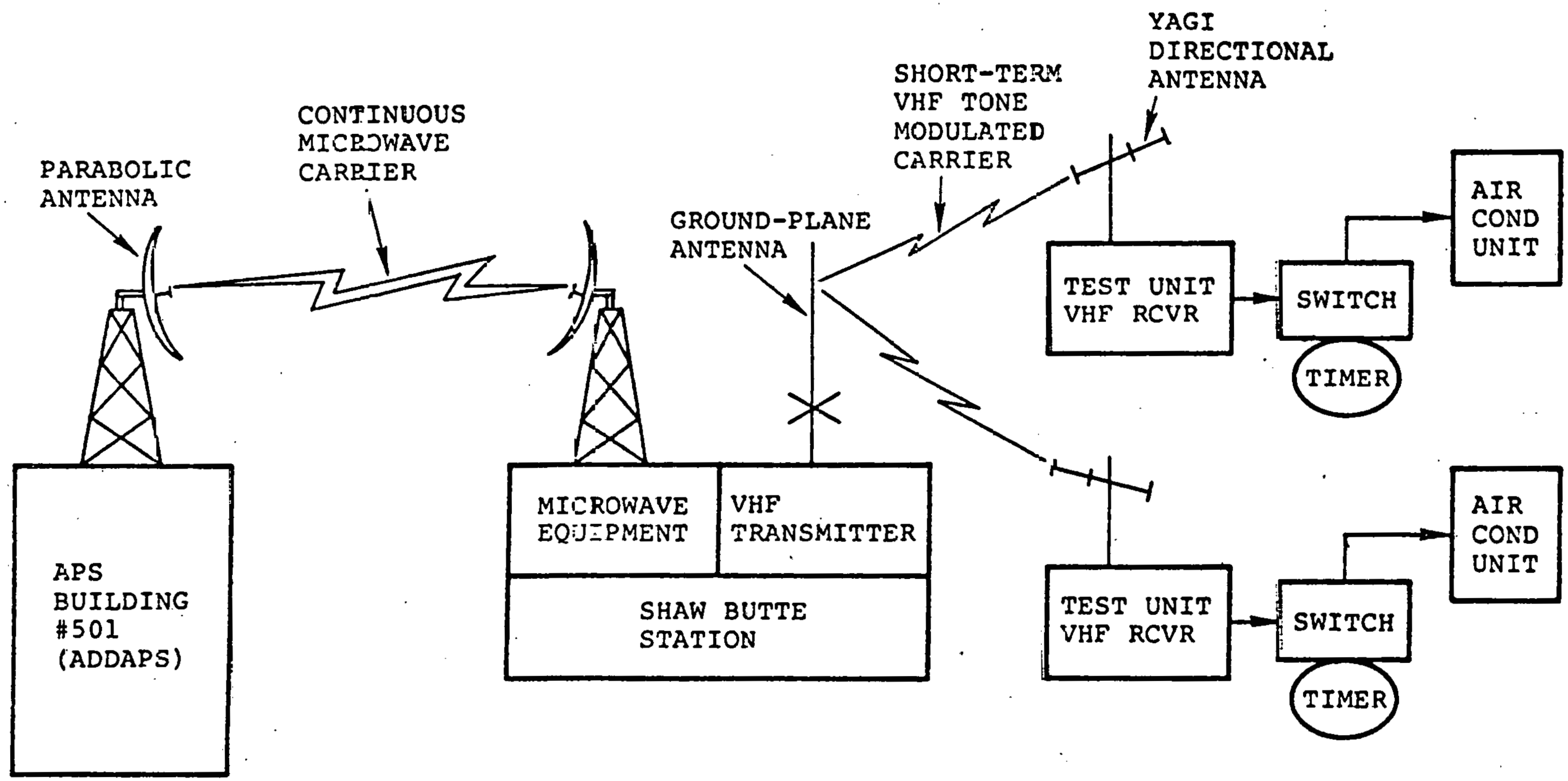
[20]Arizona Demonstration Project, Final Report, February, 1978.

FIGURE 5

Diagram of the Radio Switch Control System
Used by Arizona Public Service Company,
Arizona Demonstration Project



JMB-100 SYSTEM CONTROLLER
TRANSMITS CODED TONE MODULATED
SIGNAL TO SHAW BUTTE STATION
VIA MICROWAVE LINK

MICROWAVE CARRIER
RECEIVED AT SHAW BUTTE.
OUTPUT OF MICROWAVE
RECEIVER (CODED TONES)
ACTIVATES VLF TRANSMITTER.
VHF CARRIER IS MODULATED
BY THE CODED TONES

(TYPICAL EACH TEST UNIT)
TEST UNIT RECEIVERS,
RECEIVES AND DECODES
THE TONES AND ACTUATES
THE SWITCH AND TIMER
WHICH DISABLES THE
AIR CONDITIONING UNITS
TEMPORARILY

Source: Arizona Demonstration Project, Final Report, February 1978.

- To determine the contribution of individual residential air conditioning units to peak demand, and to determine the amount of air conditioning load which can be displaced during peak load periods.
- To determine the threshold of customer inconvenience which is incurred through control of air conditioning units during peak load periods.
- To determine the loss or gain of energy usage resulting from the deferment of customers' air conditioning load to an off-peak period.
- To evaluate this type of control as a means of shedding non-essential load during emergency conditions.
- To perform a preliminary analysis of the feasibility of trading off controlled demand for deferred capacity.[21]

Ninety-six of the 195 single family dwellings considered had control switches installed. All were from a recently constructed subdivision in northwest Phoenix, and all had an air conditioning system manufactured and installed by a local company. This company agreed to install the switches, perform service inspections, maintain the units, and keep warranties in force. Only permanent owner occupied residences with all occupants in good health were selected for the test group. Contracts were obtained from the participants in which the company offered:

- Free service inspections on air conditioning systems.
- Guarantees that the air conditioning system would be restored to its pre-test condition should any damage result from the test.
- A service telephone number to handle any questions, complaints, requests for service or any other problems which might arise in connection with the test.[22]

Consumption data were recorded at the feeder substation serving the test location. During the test loads were recorded instantaneously in 15 minute integrated intervals, on a graphic recorder, and at 30 second intervals. Ambient temperature was also recorded, but inside air temperature was not included. Table 9 shows each day the air conditioners were controlled during

[21] Ibid.

[22] Ibid.

TABLE 9

Radio Controlled Air Conditioning Data, Arizona Demonstration Project

TEST DATE	TIME OF TEST	DURATION NO. OF SHOTS INTERVAL	CONTROLLED COINCIDENCE %	AVG. LOAD BEFORE TEST START (KW)	AVG. LOAD AFTER TEST START (KW)	LOAD AFTER TEST (KW)	CALCULATED BASE LOAD (NON A/C KW)	CALCULATED NATURAL COINCIDENCE	TEMPERATURE AT TEST START (°F)	REMARKS
7-26-76	2:00 P.M.	7 Min/1/ -	N/A	840	576	840	403	49.2	102.6	Chart adjustment factor = +0.13
	3:00 P.M.	7 Min/1/ -	N/A	864	576	852	387	53.7	100.2	
	5:00 P.M.	7 Min/1/ -	N/A	900	600	972	403	55.9	101.2	
7-27-76	3:00 P.M.	17 Min/3/5 Min.	N/A	780	480	888	283	55.9	102.2	
8-10-76	4:00 P.M.	20 Min./3/5 Min.	N/A	840	564	1020	383	51.4	105.2	First shot 8 Min.
8-11-76	5:08 P.M.	22 Min/4/5 Min.	N/A	900	600	1080	403	55.9	106.3	
8-12-76	4:31 P.M.	20.5 Min/4/4.5 Min.	N/A	840	570	1020	393	50.3	108.2	
8-13-76	4:31 P.M.	20.5 Min/4/4.5 Min.	N/A	792	516	1008	335	51.4	105.5	
8-16-76	2:00 - 5:00 P.M.	3 Hours	60	672	612	-	-	-	102.7/101.1	
8-17-76	2:00 - 5:00 P.M.	3 Hours	50	672	588	-	-	-	99.2/97.1	
8-18-76	1:59 P.M.	7 Min/1/ -	N/A	684	444	780	287	44.7	102.5	
	2:27 P.M.	7 Min/1/ -		720	444	804	263	51.4	101.4	
	4:55 P.M.	7 Min/1/ -		804	504	924	307	55.9	100.7	
8-19-76	2:00 P.M.	7 Min/1/ -	N/A	-	-	-	-	-	-	
	3:30 P.M.	7 Min/1/ -		780	480	888	283	55.9	105.4	
	5:00 P.M.	7 Min/1/ -		840	564	960	383	51.4	104.1	
8-20-76	2:00 P.M.	7 Min/1/ -	N/A	-	-	-	-	-	-	
	3:30 P.M.	7 Min/1/ -		912	624	1056	435	53.7	108.8	
	5:00 P.M.	7 Min/1/ -		-	-	-	-	-	-	

TABLE 9 (continued)

TEST DATE	TIME OF TEST	DURATION NO. OF SHOTS INTERVAL	CONTROLLED COINCIDENCE %	AVG. LOAD BEFORE TEST START (KW)	AVG. LOAD AFTER TEST START (KW)	LOAD AFTER TEST (KW)	CALCULATED BASE LOAD (NON A/C KW)	CALCULATED NATURAL COINCIDENCE	TEMPERATURE AT TEST START (°F)	REMARKS
8-23-76	2:00 P.M. 3:30 P.M. 5:00 P.M.	7 MIN/1/- 7 MIN/1/- 7 MIN/1/-	N/A N/A N/A						105° 104° 103°	BAD MICROWAVE CHANNEL
8-24-76	2:00 -5:00 P.M.	2 frequencies off every 12 minutes	N/A						106°	Radio check only Increment too small
8-25-76	2:00 - 5:00 P.M.	4 frequencies off every 12 minutes	N/A							Radio check only
8-26-76 8-27-76	2:00 - 5:00 P.M.	4 frequencies off every 12 minutes	N/A						104° 103°	Radio check only
8-30-76	2:00 P.M. 3:30 P.M. 5:00 P.M.	7 MIN/1/- 7 MIN/1/- 7 MIN/1/-	N/A N/A N/A						107° 107° 104°	
8-31-76	2:00 P.M. 3:30 P.M. 5:00 P.M.	7 MIN/1/- 7 MIN/1/- 7 MIN/1/-	N/A N/A N/A							
9-1-76	2:00 P.M. 3:30 P.M. 5:00 P.M.	7 MIN/1/- 7 MIN/1/- 7 MIN/1/-	N/A N/A N/A							
9-2-76	2:00 P.M. 3:30 P.M. 5:00 P.M.	7 MIN/1/- 7 MIN/1/- 7 MIN/1/-	N/A N/A N/A							PROGRAMMER MALFUNCTION
9-3-76	2:00 P.M. 3:30 P.M. 5:00 P.M.	7 MIN/1/- 7 MIN/1/- 7 MIN/1/-	N/A N/A N/A							PROGRAMMER MALFUNCTION
9-7-76	2:00 P.M. 3:30 P.M. 5:00 P.M.	7 MIN/1/- 7 MIN/1/- 7 MIN/1/-	N/A N/A N/A							
9-8-76	2:00 P.M. 3:45 P.M. 5:00 P.M.	7 MIN/1/- 7 MIN/1/- 7 MIN/1/-	N/A N/A N/A	696 756 792	612 624 660	744 804 948	557 537 573	15.7 24.6 24.6	100.7 101.3 97.6	
9-9-76	2:15 P.M. 3:30 P.M. 5:00 P.M.	7 MIN/1/- 7 MIN/1/- 7 MIN/1/-	N/A N/A N/A							
9-10-76	2:15 P.M. 3:30 P.M. 5:00 P.M.	7 MIN/1/- 7 MIN/1/- 7 MIN/1/-	N/A N/A N/A							

Source: Arizona, Final Report, February 1978.

July, August, and September, and average load before and after the air conditioners were tested. The reductions were in the neighborhood of 250 to 300 KW. However, when the air conditioners were turned back on, the load was greater than before the test started--sometimes it was as much as 150 KW greater.[23] The same "rebounding" phenomenon occurred in Pacific Gas and Electric's tests of air conditioning control: see Figures 6 and 7. Figure 6 is for a one day test in Arizona and Figure 7 is for a one day test in Fresno, California by PG&E.

A mild summer prevented testing the system through the full range of operational conditions. This prevented collection of data which would have established conclusive results.

> The daily temperatures during the test period was well below that of previous system peaks. During only one day was the temperature over 107°F. The previous year there were 12 days with temperatures higher than 116°F.[24]

Despite the lack of suitable temperatures for the study, one significant feature of controlling air conditioning load was observed. In attempting to shave a daily peak which is less than a maximum system peak, air conditioning load can rebound and generate peaks exceeding those which would be experienced under a non-controlled situation. Once central control is undertaken, the natural diversity of the air conditioning load is lost. To prevent all air conditioning units from demanding power simultaneously, the control must be continued well past the daily peak, or a systematic plan of phased relaxation of control must be followed.

Customer reaction was generally favorable, but the atypically low temperatures during the test probably invalidated most of the results. Eighty-three percent of the 60 who responded to a mailed survey felt no change in temperature after the switches were installed and functioning. However, 26 percent wished to have the

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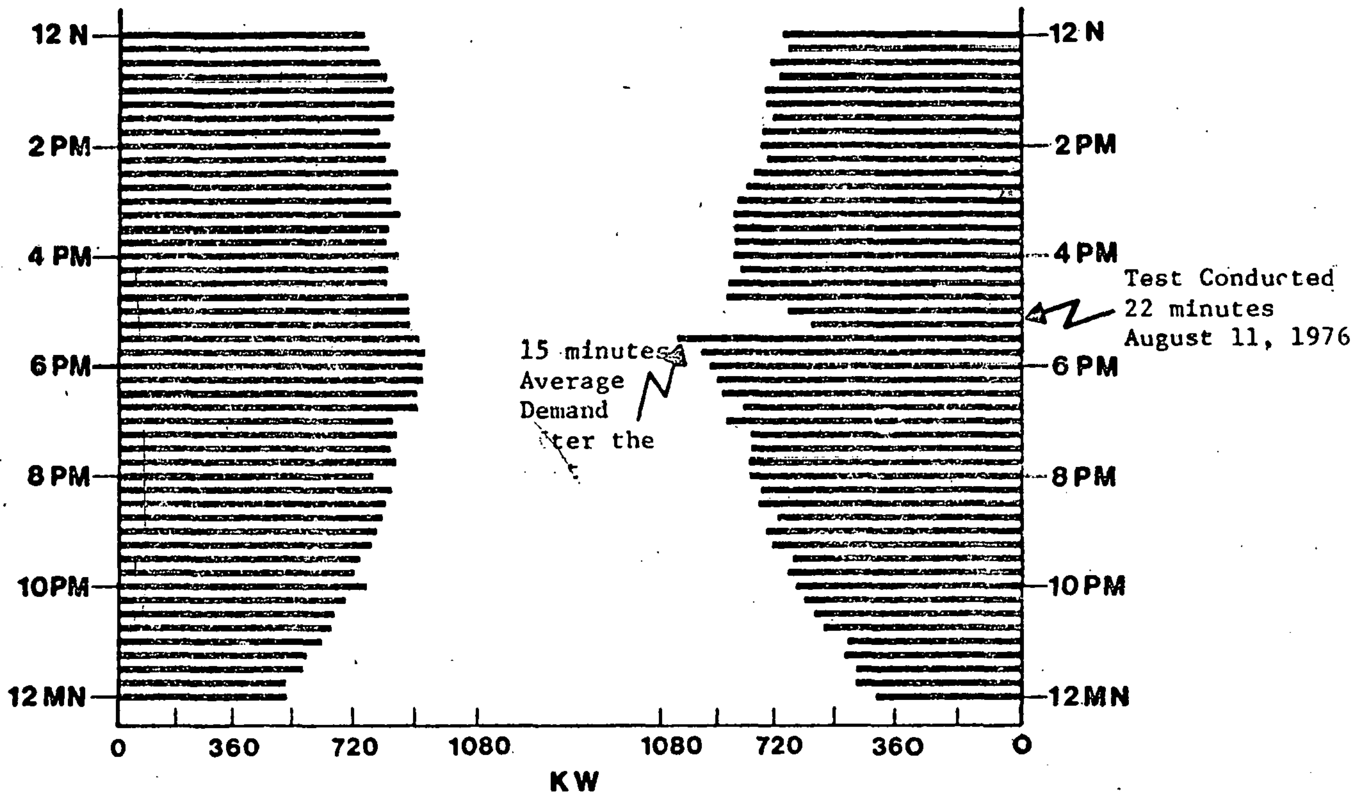
[23] See Table 9.

[24] Arizona Final Report, loc. cit.

FIGURE 6

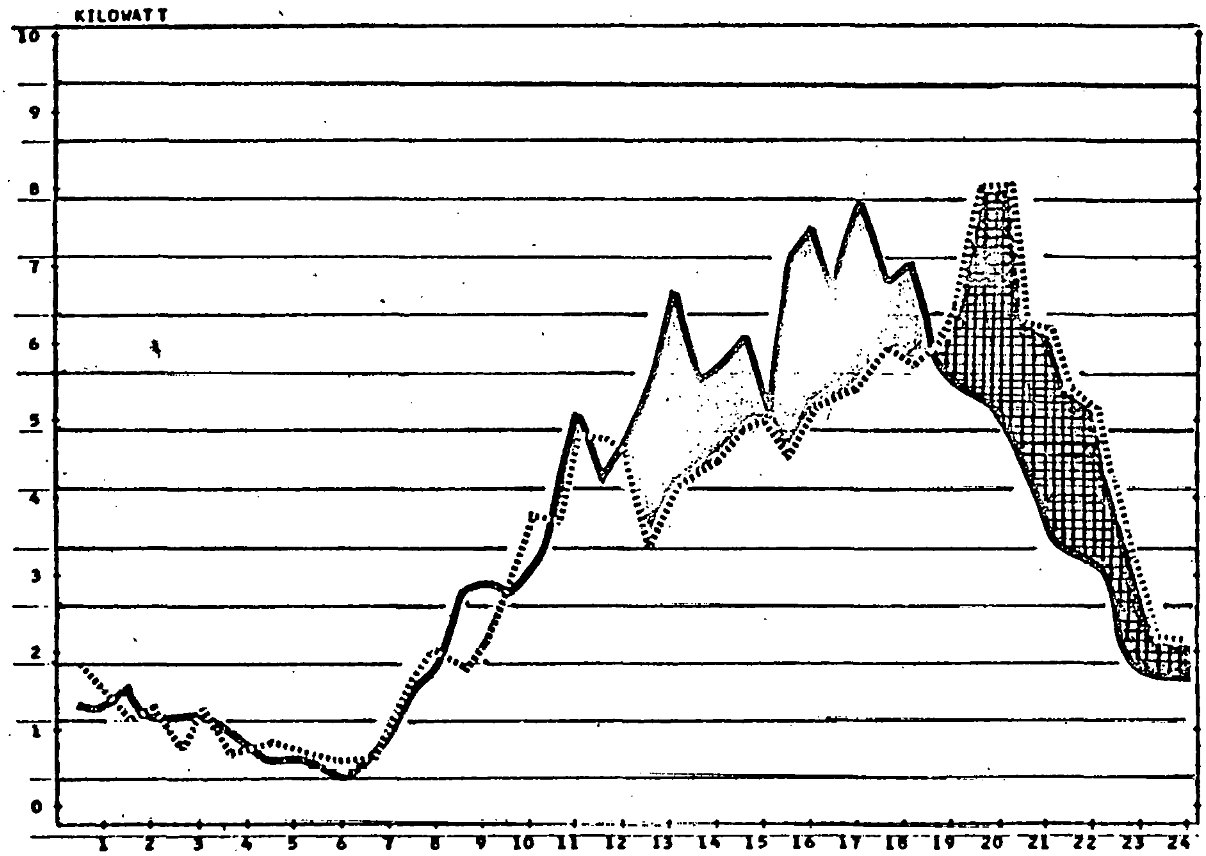
Comparison of a Demand Profile of a Test Run and Normal Operation for Similar Ambient Temperature Conditions, Arizona Demonstration Project



Source: Arizona, Final Report, February 1978.

FIGURE 7

Composit Weekday Daily Load Curves for All Fresno Long Cycle Test Homes, Pacific Gas and Electric, California Demonstration Project



Fresno Long Cycle Individual Test Homes

—— Diversity Test Day: Max Temp. 106° F

-------- Cycling Test Day: Max Temp. 107° F

Source: California Energy Commission, "A Second Year Report to the Department of Energy", May 1979.

switch removed, 30 percent were unsure and 44 percent indicated that they would not object to retaining the switch permanently. Four customers had air conditioner problems: one thought it was caused by the switch, the others were not sure.

The Ohio Project developed an innovative strategy to prevent needle peak rebound from the controlled air conditioning load in the event of a breakdown of either the central computer or the data link between the computer and transmitters. Ohio experienced two periods of severe noise on the Ohio Bell cable link. To prevent a similar interruption from suddenly allowing a rebound in air conditioning load, the link between the computer and the transmitter was monitored. In each five minute period the computer interrogated the semi-smart transmitter system with a test signal which reset a timer. If no test signal was received by the transmitter, the timer completed its cycle, shifted the transmitter to a pre-scheduled program, and transmitted a request for service to utility personnel.

In California a number of different radio control tests were conducted. Among these was a test by PG&E of air conditioners and one by Southern California Edison of residential hot water heaters.

In the PG&E tests both Motorola and Fisher Pierce switches were used. The utility could not detect a significant difference between the two switches but it did notice a difference between batches from each vendor. The quoted delivery time of 6-18 weeks was usually exceeded. Initially a single tone switch was used but this allowed only ten addresses, because the others were already in use. To expand the system, two tone receiver switches were purchased in 1979. To the utilities' surprise the addressing format differed between the vendors. About 3 percent of the two tone receiver switches were defective.[25]

The base transmitter was a 250 watt unit. On two occasions, it experienced a partial failure which reduced the signal output.

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[25] California Demonstration Project, "A Second Year Report . . ." _loc. cit._

There was no monitoring system to detect partial failure. There were also repeated failures of leased telephone lines during the test period.

Hand held transmitters, for checking the operation of receiver switches and verifying the codes set into the receivers, were received too late from the vendor to be used in the test. There was also a problem of computability between the addressing schemes of the two vendors' equipment.[26]

PG&E subcontracted the installation of the switches. The quality of work varied: one contract was cancelled for substandard work, and some damage was done to customer equipment through faulty installation. Bids for the installation varied by as much as 500 percent.[27]

PG&E recommended that in the future, switches be designed so that a flush mounting of the switch would be possible. This would lessen some objections to units protruding from the wall, and reduce the possibility of vibration damaging the switch.[28]

Customer acceptance was considered a crucial factor in potential air conditioning control projects. Over 1,700 customers participated in the Demonstration Project. The major design features of the program were:

- Voluntary participation.
- Incentives to participants.
- Participation limited to single family, owner-occupied homes with central air conditioners.
- Pole and individual magnetic tape meters to record demand.
- Limited number of in-house thermographs and indoor/outdoor temperature mag tape recorders installed in individual homes.

As an inducement to customer participation in the experiment,

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[26]California Demonstration Project, Proceedings, loc. cit.

[27]Ibid.

[28]Ibid.

PG&E paid a rate reduction of $3 per KW of installed air conditioner capacity, and agreed to pay for any air conditioning service required during the test. In thirty-six instances such service was necessary. The average cost of the service was $55 per call.[29]

In 1977 Southern California Edison (SCE) conducted tests to control residential water heating. The purposes of the test were to 1) determine average peak load for three types of dwellings (apartments, condominiums, and single family residences), 2) determine the load rebound both in magnitude and duration, and 3) determine effectiveness of control equipment.

Customer participation was voluntary but customers were compensated by a one time payment of $4 and a monthly payment of $3 during the test period. As in the other Projects, switches were installed by electrical contractors. During the test 35 out of 71 switches located in single family residences did not function.[30]

Average demand during summer peak periods averaged .348 KW per customer, which was much less than the 1.0KW which had been anticipated. A half hour interrupt generated a rebound which was 2.5 to 4 times the normal load, while a two hour interrupt created a rebound of 6.5 to 12 times normal. SCE concluded that peak shaving through hot water heating control was not sufficiently economical. Additionally, the rebound characteristic was considered to be unsuitable for implementation.[31]

A feature unique to the California study was investigation of the daily cycle of the interruption. By testing interruptions of duty cycles of up to 50 percent and observing the effect upon load drop and customer acceptability, it was possible to make informed estimates of an optimal strategy for implementing load controls.

Figure 8 illustrates the relation between duty cycle (percent off time) and load reduction. As shown by the figure, off

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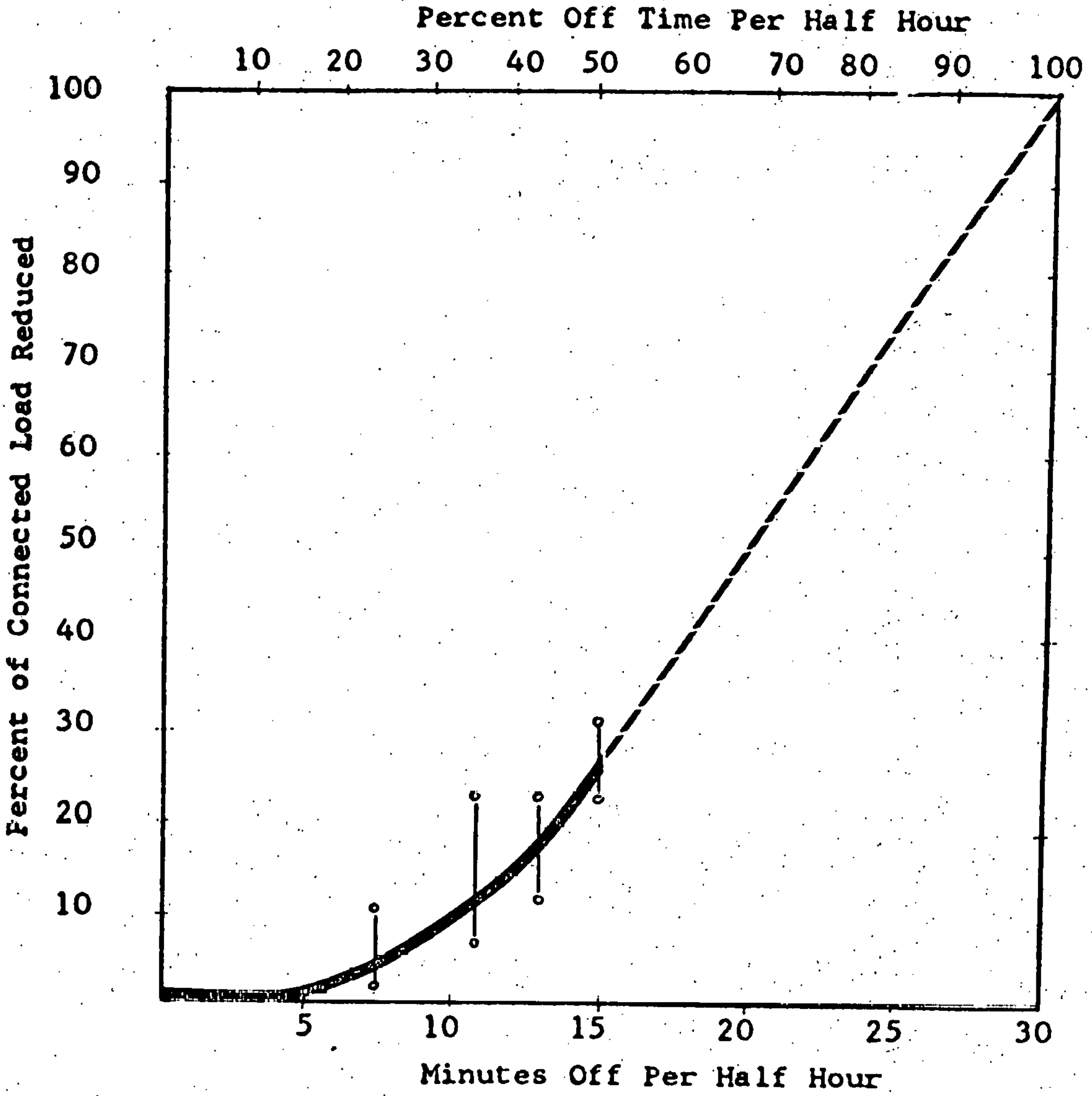
[29] Ibid.

[30] Ibid.

[31] Ibid.

FIGURE 8

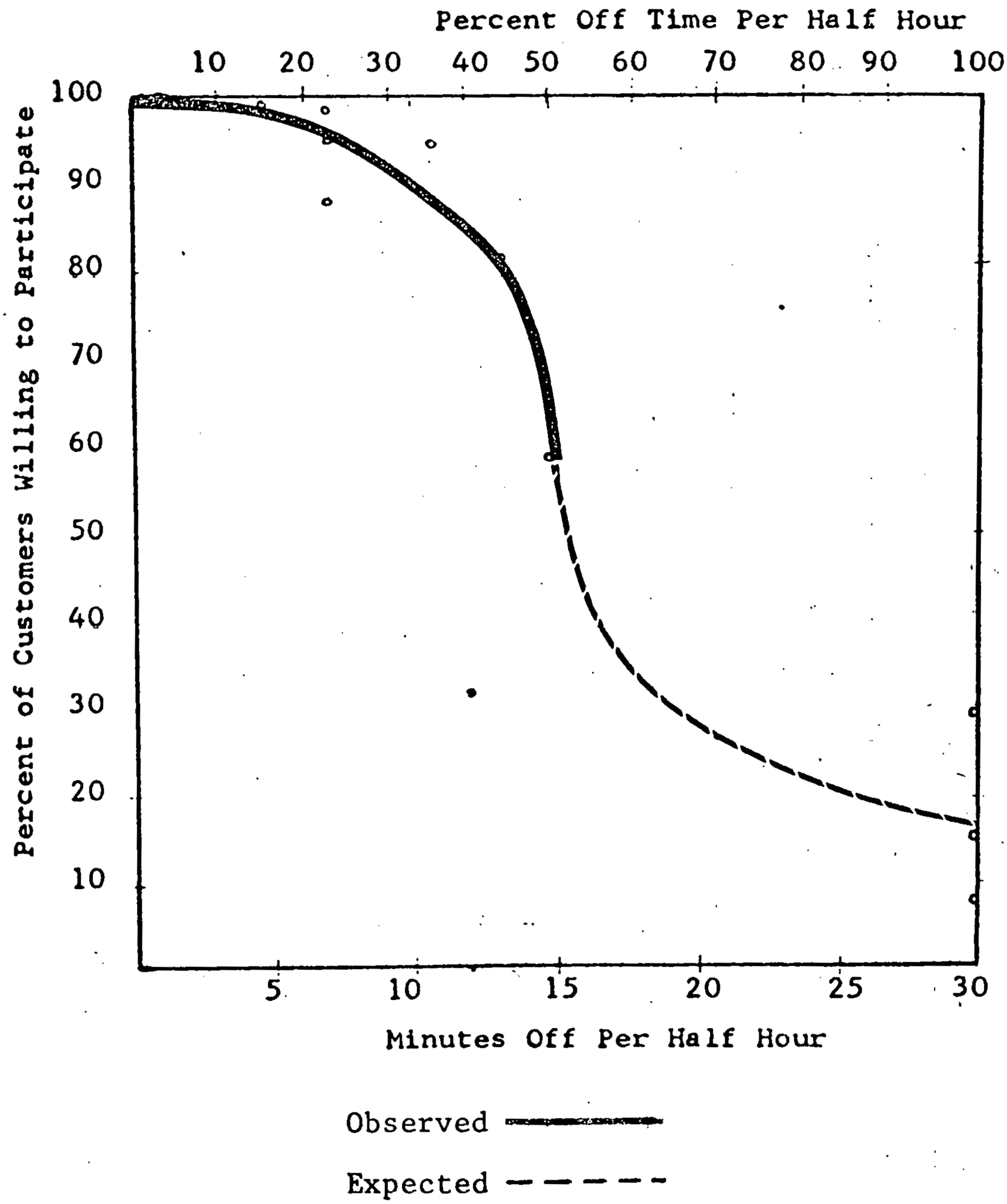
Observed and Expected System Load Drop Versus Cycle Off Time, California Demonstration Project



Source: California Energy Commission, "A Second Year Report to the Department of Energy", May 1979.

FIGURE 9

Observed and Expected Customer Participation Versus Cycle Off Time, California Demonstration Project

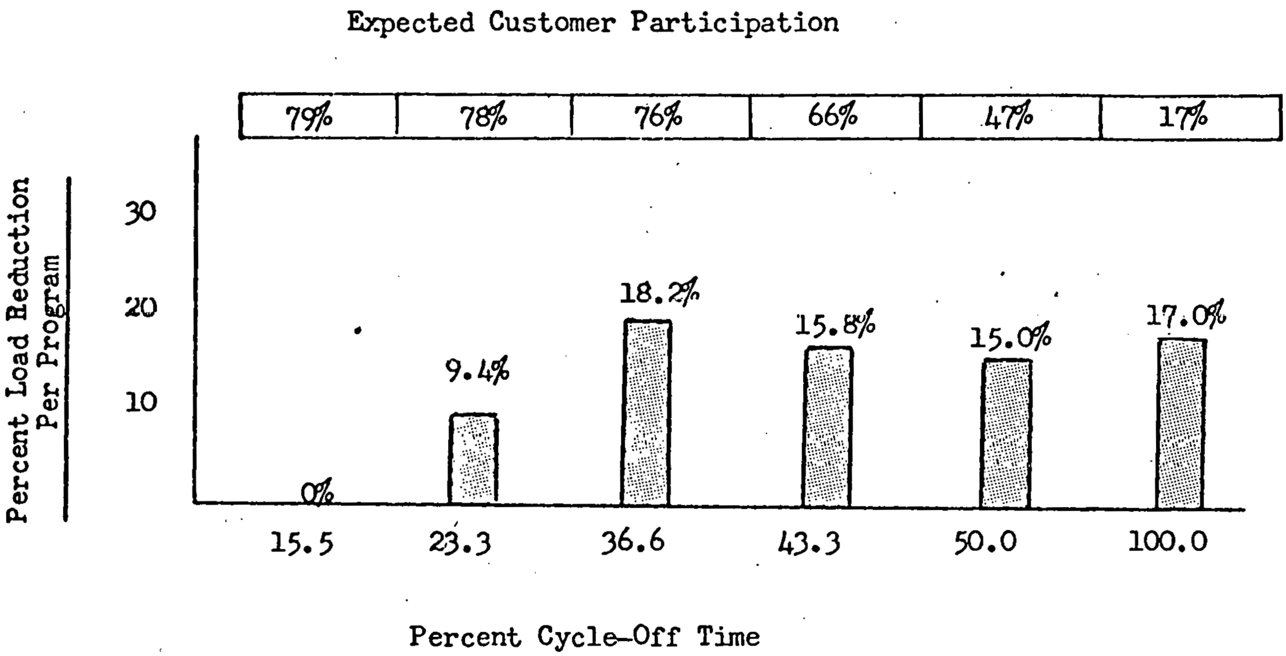


Source: California Energy Commission, "A Second Year Report to the Department of Energy", May 1979.

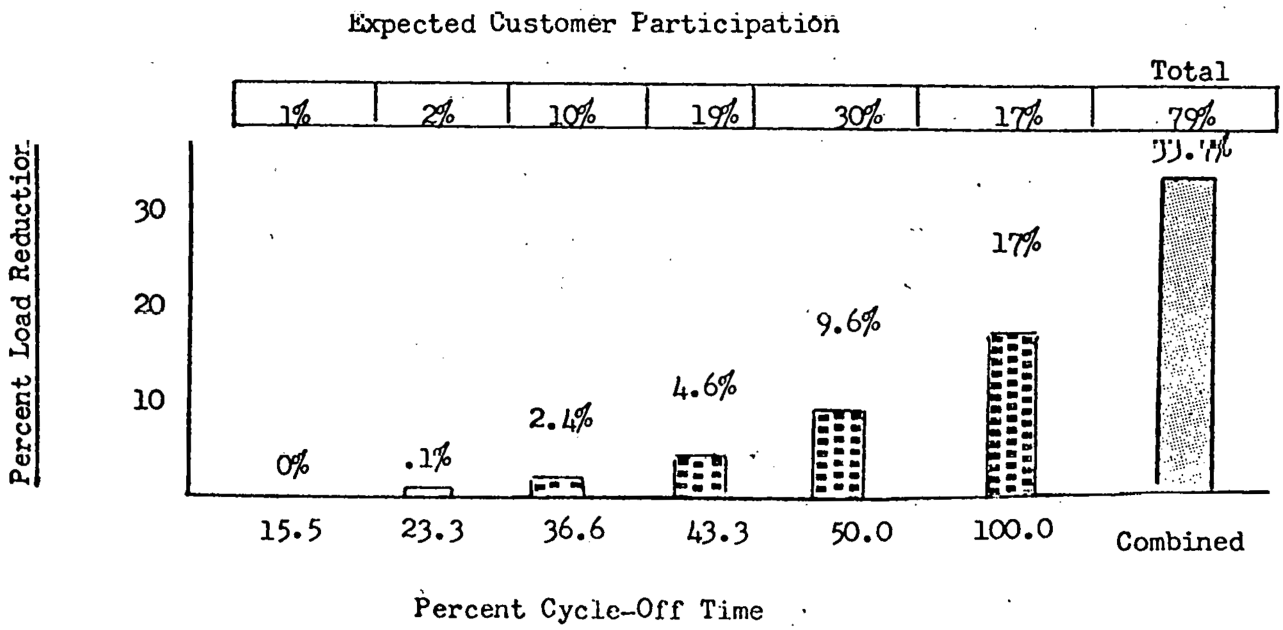
FIGURE 10

Comparison of Cycling Strategies by Expected Customer Participation and Load Reduction, California Demonstration Project

(a) Program Offering a Single Cycling Strategy



(b) Program Offering a Choice of Cycling Strategy



Source: California Energy Commission, "A Second Year Report to the Department of Energy, May 1979.

times of up to 25 percent have very little effect on load. With duty cycles this low, the effect of the interruption in power is to shift the time when the air conditioner compressor is running. No energy is saved until the interruption begins to reduce the running time of the compressor. As the length of the interruption increases and energy begins to be saved, inside air temperature increases. Willingness of customers to continue air conditioning load control varies inversely to the length of the interruption and the increase in inside air temperature. This comparison is shown in Figure 9.

After examining the data given here as Figures 8 and 9, the California Energy Commission suggested that an optimal air conditioning load program would offer the consumer a choice of the length of interruption. Figure 10 depicts the potential energy savings in programs offering customers single cycling strategy and a choice of the amount of off-time. When the customer can choose the length of interruption, almost twice as much load can be controlled as in programs offering only single interruptions.

VOLTAGE REDUCTION

The only Project to attempt a controlled voltage reduction (CVR) program was California. The program in California was officially begun in early 1977 when the Public Utilities Commission (PUC) informed utilities that they should submit plans for reduction as soon as possible. Before the notice, however, the PUC staff requested Pacific Gas and Electric to make a series of voltage reduction tests in some of its service areas. These tests proved to be successful in reducing the demand for electricity, though there were some problems in the early stages which had to be corrected.

In one test voltages were reduced by 5 percent or approximately 6 volts. The tests were made without notice to the public. No efforts were made to insure that minimum voltages in the services under test remained within the ANSI specified standard of 114 volts. No attempt was made during this test to measure the energy savings, as it was solely preliminary.[32]

Another test to measure energy savings was made at the Daly City substation. Here the service area was divided into control segments and test segments. Each day the control and test areas were alternated. In the test area the voltage was reduced by 3 volts. Total KWH's in the control and the test areas were measured by pulse generating meters and were recorded on magnetic tape. Test periods included September and January--the area's summer and winter peak-load periods. Test results indicated a 2.5 percent decrease in energy consumed for a 3 volt reduction in voltage. Only one complaint was received during the test.[33]

Other tests were undertaken by PG&E: the Stockton division ran a 71-day reduced voltage test on their own division headquarters office building. A 5 percent reduction in voltage reduced energy consumption by 3.9 percent. Three distribution circuits were tested and initial results showed a 2 percent decrease in energy consumption for a 3 volt reduction in voltage.[34]

The Stockton division also tested the effect of reduced voltage on some electrical appliances. The results are reproduced in Table 10.

The appliances tested were units commonly found in households and small businesses. All items tested were inductive loads. Though it does not appear in the tables, it is possible to compute the output of the appliances in appropraite units relative to the energy consumed (watts). Mercury Vapor Lamp output was constant over the range of voltages tested. The fluorescent lamp's output per unit energy rose slightly, as did the television's. The fan's output rose slightly up to 110 volts and

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[32] California Demonstration Project, Electric Distribution Feeder Voltage Regulation for Effective Energy Conservation, California Public Utilities Commission, San Francisco, California, January 27, 1978.

[33] Ibid.

[34] Ibid.

TABLE 10

Pacific Gas and Electric Tests of
Selected Electrical Appliances
California Demonstration Project

Appliance	Voltage (vac)	Current (amps)	Watts (calculated)	Light Meter
Mercury Vapor Lamp[a]	124.0	3.70	222.4	56.5
	120.0	3.40	207.1	52.0
	118.5	3.28	199.0	50.0
	117.0	3.18	193.0	48.0
	115.5	3.05	184.6	46.0
	110.0	2.70	163.9	40.0
Fluorescent Light Fixture[b]	124.0	1.32	146.5	66.0
	120.0	1.27	138.7	62.5
	118.5	1.25	135.8	62.0
	117.0	1.23	133.0	60.0
	115.5	1.22	131.6	59.9
	114.0	1.19	127.5	58.0
	110.0	1.14	119.6	56.0
Black & White Television 9 inch[c]	124.0	0.96	119.0	5.5
	120.0	0.93	112.2	5.0
	118.5	0.91	107.8	5.0
	117.0	0.90	105.3	5.0
	115.5	0.89	102.7	5.0
	110.0	0.85	93.4	4.0
	100.0	0.77	76.9	3.9
Ventilating Fan[d]				RPM
	124.0	1.55	176.3	1050
	120.0	1.56	171.7	1000
	118.5	1.57	170.6	1000
	117.0	1.57	167.8	1000
	115.5	1.57	165.7	1000
	110.0	1.60	160.5	920
Kitchen Refrigerator[e]	124.0	2.58	214.1	-
	120.0	2.20	166.1	-
	118.5	2.17	158.7	-
	117.0	2.15	156.6	-
	115.5	2.13	154.8	-
	110.0	2.10	151.5	-

(continued)

TABLE 10 (continued)

Appliance	Voltage (vac)		Current (amps)	Watts (calcu.)	Time Required to pump to 10 PSI
Air Compressor[f]	Off	Running			
	124.0	119.0	9.1	589.8	44
	120.0	116.0	8.7	557.0	44
	118.5	115.0	8.5	539.5	44
	117.0	113.0	8.3	524.5	46
	115.5	112.0	8.2	520.2	46
	110.0	107.0	7.6	480.4	48

Source: California Public Utilities Commission, "Electric Utility Distribution Feeder Voltage Regulation For Effective Energy Conservation", January 27, 1978.

[a]H39 Mercury Vapor Lamp in Holophane Fixture, 120 Volt, 175 watt, 3.30 amps. Light meter 4.6 feet away.

[b]GE F-40-CW Main Lighter, Cool White, 40 watt, 118 volt 1.3 amps. Light meter 4.6 feet away.

[c]Sharp Model TM-68P, 100 watt, 120 volt, 60 cycle. Light meter 6 feet away.

[d]Hartzell Propeller Fan, 115 volt, 3.5 amps 60 cycle, 1700 RPM.

[e]Dwyer Model E39, 115 volts compressor.

[f]Keystone by Dayton, ½ HP., 10 amp 115 volt.

then fell. The air compressor used slightly fewer watt seconds to attain 10psi. Since no measure of the refrigerator's output was included, we assume that the results would have been essentially the same as those of the compressor. One conclusion of the tests was, "As long as voltage is maintained at 114 volts no significant deterioration of appliances tested resulted; below 114 volts performance did fall off."[35]

California State University, Sacramento, commissioned tests of appliance performance at reduced voltages. The tests were conducted well below the lower limits of accepted service voltage, and do not apply to the range of voltage reductions contemplated in the conservation voltage reduction program. The test did, however, point out the problems when motors designed for 230 volt supply are used on 208 volt systems. All three of the units tested were at 230-208 volts: their efficiency fell off markedly at voltages below 230 volts. Since one of few recurrent problems that resulted during the CVR program was the misapplication of motors designed for 220 power to 208 supplies, it seems that a public awareness program would be helpful. Evidently the electrical manufacturing and contracting industry is well informed on this matter, but do-it-yourselfers and other amateurs are not. A close reading of Table 11, especially note (d) discloses part of the problem, but ability to interpret the table appears to require training. More accessible dissemination of the information may help attain better working results with motors.

The manufacturers indicated that their equipment was not intended for use below 197 volts: at 191 volts the motors ran hot and started with difficulty. Since 208/120 volt systems are allowed by standards to go as low as 191 volts, a mismatch of motors designed for higher voltage supplies will cause problems when operated on 208/120 lines operating at the lower limits of allowed voltages. These problems were extensive enough that it

[35] Ibid.

[36] Ibid.

TABLE 11

American National Standard for Voltage

NOMINAL SYSTEM VOLTAGE (Note a)			VOLTAGE RANGE A (Note b)			VOLTAGE RANGE B (Note b)		
			Minimum		Maximum	Minimum		Maximum
Two-wire	Three-wire	Four-wire	Utilization Voltage (Note c)	Service Voltage	Utilization and Service Voltage (Note e)	Utilization Voltage (Note c)	Service Voltage	Utilization and Service Voltage
Single-Phase Systems								
120			110	114	126	106	110	127
	120/240		110/220	114/228	126/252	106/212	110/220	127/254
Three-Phase Systems								
		208Y/120	191Y/110	197Y/114	218Y/126	184Y/106 (Note d)	191Y/110 (Note d)	220Y/127
		240/120	220/110	228/114	252/126	212/106	220/110	254/127
	240		220	228	252	212	220	254
		480Y/277	440Y/254	456Y/263	504Y/291	424Y/245	440Y/254	508Y/293
	480		440	456	504	424	440	508
	600 (Note f)		550	570	630 (Note f)	530	550	635 (Note f)
	2400		2160	2340	2520	2080	2280	2540
		4160Y/2400	3740Y/2160	4050Y/2340	4370Y/2520	3600Y/2080	3950Y/2280	4400Y/2540
	4160		3740	4050	4370	3600	3950	4400
	4800		4320	4680	5040	4160	4560	5080
	6900		6210	6730	7240	5940	6560	7260
		8320Y/4800		8110Y/4680	8730Y/5040		7900Y/4560	8800Y/5080
		12000Y/6930		11700Y/6760	12600Y/7270		11400Y/6580	12700Y/7330
		12470Y/7200	(Note g)	12160Y/7020	13090Y/7560	(Note g)	11850Y/6840	13200Y/7620
		13200Y/7620		12870Y/7430	13860Y/8000		12540Y/7240	13970Y/8070
		13800Y/7970		13460Y/7770	14490Y/8370		13110Y/7570	14520Y/8380
	13800		12420	13460	14490	11880	13110	14520
		20780Y/12000		20260Y/11700	21820Y/12600		19740Y/11400	22000Y/12700
		22860Y/13200		22290Y/12870	24000Y/13860		21720Y/12540	24200Y/13970
	23000			22430	24150		21850	24340
		24940Y/14400	(Note g)	24320Y/14040	26190Y/15120	(Note g)	23690Y/13680	26400Y/15240
		34500Y/19920		33640Y/19420	36230Y/20920		32780Y/18930	36510Y/21080
	34500			33640	36230		32780	36510

Higher Voltage Three-Phase Systems in kV

Nominal System Voltage	Maximum Voltage
46	48.3
69	72.5
115	121
138	145
161	169
230	242

For these systems Range A and Range B limits are not shown because, where they are used as service voltages, the operating voltage level on the user's system is normally adjusted by means of voltage regulation to suit his requirements.

NOTES:

(a) Three-phase three-wire systems are systems in which only the three phase conductors are carried out from the source for connection of loads. The source may be derived from any type of three-phase transformer connection, grounded or ungrounded. Three phase four-wire systems are systems in which a grounded neutral conductor is also carried out from the source for connection of loads. Four-wire systems in Table are designated by the phase-to-phase voltage, followed by the letter Y (except for the 240/120-volt delta system) a slant line, and the phase-to-neutral voltage. Single-phase services and loads may be supplied from either single-phase or three-phase systems. The principal transformer connections that are used to supply single-phase and three-phase systems are illustrated in Appendix A.

(b) The voltage ranges in this table are illustrated in Appendix B.

(c) Minimum utilization voltages for 120-600 volt circuits not supplying lighting loads are as follows

Nominal System Voltage	Range A	Range B
120	108	104
208	187	180 (Note d)
240	216	208
480	432	416
600	540	520

(d) Many 220 volt motors were applied on existing 208-volt systems on the assumption that the utilization voltage would not be less than 187 volts. Caution should be exercised in applying the Range B minimum voltages of Table 1 and Note (c) to existing 208-volt systems supplying such motors.

(e) For 120-600 volt nominal systems, voltages in this column are maximum service voltages. Maximum utilization voltages would not be expected to exceed 125 volts for the nominal system voltage of 120, nor appropriate multiples thereof for other nominal system voltages through 600 volts.

(f) Certain kinds of control and protective equipment presently available have a maximum voltage limit of 600 volts, the manufacturer or power supplier or both should be consulted to assure proper application.

(g) Utilization equipment does not generally operate directly at these voltages. For equipment supplied through transformers, refer to limits for nominal system voltage of transformer output.

* Information from American National Standard C92.2-1967.

Extra High Voltage Three-Phase Systems in kV

Preferred Nominal System Voltage	Preferred Maximum Voltage
345	362
500	550
700	765

Source: California Public Utilities Commission, "Electric Utility Distribution Feeder Voltage Regulation for Effective Energy Conservation", January 27, 1978.

was felt that changes in the codes and in practices of equipment suppliers may be necessary.[36]

Emarendole substation in San Francisco made a 4-day test of a 2.5 percent reduction in voltage on 11 feeders supplying 43 MW of load. A 20 percent decrease in energy use was experienced, but the test was discontinued after numerous inquiries and complaints by customers.

In contrast to most of the other Demonstration Projects, improvement in local voltage regulation involved little interaction between the utility and the customers. Few consumers were aware of the actual voltages at which they were supplied electrical power nor was there any awareness of voltage fluctuations in their supply. The exception was during gross low voltage conditions (brown-outs). Most electrical power usage was tolerant of considerable variation in supply voltages without perceptibly affecting power consumption. Changes in voltage levels and regulation practice can be made exclusively from the utilities side without either the knowledge or consent of the customer. However, the changes in voltage level and regulation can be carried out to their fullest only with the cooperation of customers and with producers and suppliers of electrical equipment.[38]

Although PUC staff stated that customer impact was the primary concern, no efforts were made before the test to determine which customers would experience below-standard voltage and to take corrective action before beginning the tests. During the test some customers experienced dim lighting; shrinking, fading and flickering TV screen pictures; slow heating times for electrically heated kilns; gluing heaters, slower plating action; and the start-up of a back-up power generator for an airport control tower. Corrective actions taken appeared to be more responsive to the customer affected than to the validity of the complaint.

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[37] Ibid.

[38] Ibid.

The test of the control tower was discontinued even though the voltage was measured at the distribution point as being 118 volts. The problem for the control tower was not that the voltage supplied was too low for adequate operations, but that the takeover point for the back-up generator was set too high. No corrective action was taken for residential customers in several instances, even though the voltage supplied was as low as 109 volts. In some cases the complaint was resolved by adjusting the customer's transformer taps or by replacing the transformer.[39]

After the preliminary tests and the PUC's notice, most of the large utilities in California identified distribution feeders with appropriate loads for voltage reduction and implemented a voltage reduction program. As a result of the tests an improvement was made in the method of reducing excess voltages between the test phase and actual implementation. In the test phase the voltage was reduced at the distribution feeder. In most cases prior examination of the feeder network was made, to insure that no customer's voltage meter fell below 114 volts. In the implementation, however, the sensing input to the feeder's voltage regulation equipment was set to read the voltage of the customer experiencing the greatest voltage drop. When the regulator was set to supply the end-of-line customer 114 volts, it automatically controlled the feeder's voltage in order to minimize excess voltage while maintaining all customers at or above minimum standards. At this level of implementation CVR involved a minimum of additional costs to a utility. Most of the necessary changes were made as a part of normal inspection and maintenance. This phase proved to be a very cost effective energy conservation measure.[40]

All residential and commercial loads in the Project experienced a decrease in energy consumption, with improved voltage regulation and reduction of overall voltage regulation toward minimum rather than maximum standards levels. Experiences with

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[39] Ibid.

[40] Ibid.

industrial and agricultural loads were mixed. In some cases reductions in voltage levels resulted in slight increases in energy consumption. Investigation continued into categories of industrial and agricultural use that might benefit from reduced voltages. There are several distinctions between residential commercial loads and industrial agricultural loads that might account for differences in voltage reductions. Until recently, energy consumption of residential and commercial appliances has been unimportant to the consumer. Therefore, manufacturers of such appliances had little incentive to make efforts to design items which utilized electricity efficiently. Motors for the appliances tended to be over-specified in power and consequently dissipated more energy than necessary. For any given load, the most efficient conversion of electrical energy is accomplished by a motor in which the phase of rotation of the motor lags behind the phase of alternating current. Limitations to allowable lags of the motor are set by safety margins which insure that the motor has adequate power for variation in load without stalling. Reducing voltage levels has the effect of reducing the effective power rating of a motor, increasing the phase lag of a motor under a given load and increasing the motor's efficiency. Industrial and agricultural motors may already be close enough to optimum design that reduced voltages do little to increase efficiency.[41]

The expenditures in the CVR program by PG&E had been minimal, considering the magnitude of the resulting energy savings. The expenditures in 1979 were $138,000, and the total is expected to increase to $385,000 by 1981. The number of kwh saved in 1979 was about 635 million, expected to increase to 649 million KWH in 1981. The 1979 marginal cost of a kwh was 6.5 cents, so the dollar savings in 1979 was slightly more than $41 million.[42]

Further savings in energy are available through CVR but they involve capital expenditures. The PUC is continuing to identify

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[41] Ibid.

[42] Telephone interview, Steve Reynolds and Byron Tomilson, Pacific Gas and Electric, August, 1980.

the extent of these savings and the cost involved. One source of savings might result from reducing the area served by a local feeder. A smaller voltage drop would be experienced at end points if the size of the local network were reduced. This would allow lower voltage setting without reducing end-of-line customers' voltage below standard. Other measures would make more use of adjusting step-down transformers at the customer's meter. End-of-line customers would have their transformers adjusted to maintain minimum voltage. The ratio of costs to savings of these and other more extensive measures has yet to be determined.[43]

SUMMARY

Utility initiated load management techniques discussed in this chapter are: 1) ripple control, 2) radio control, and 3) voltage regulation.

The Vermont Project installed a ripple system to interrupt power to hot water heaters and hydronic heat storage units. Customer reaction to the experiment was quite favorable: all 300 test customers voluntarily remained on the interruptible rate at the Project's conclusion. About one-half of the customers reported no need to change hot water use habits in response to the rate. The likelihood of consumption change appears to have been a function of hot water tank size and family size.

Radio control systems were used in several Projects to control water heaters (California, Ohio), irrigation pumps (Arkansas), and air conditioners (Arkansas, Arizona, California, Ohio).

The Arkansas Project tested radio controlled interruption of air conditioning in 218 residences and irrigation pumping on 12 farms. Since few technical problems were encountered during the test the response of both residential and farm customers was generally favorable. The utility moved on to a full scale implementation of radio control, and installed 33,500 switches by 1980. It was estimated that full implementation of air conditioning

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[43]California Demonstration Project, loc. cit.

controls would defer 125 MW of new peak generating capacity, and make 500 MW of load available for emergency shedding.

The Arizona Project tested radio control of air conditioning load in 96 single family dwellings in one development. While radio control resulted in load reductions of between 250 and 300KW there was a pronounced "rebound" response at the end of the off-phase; load sometimes increased as much as 150KW above the level reached before the units were switched off.

Pacific Gas and Electric Company (in the California Project) tested radio control of air conditioning and learned a good deal about variations in the quality of equipment and about the possibilities of incompatibility between components ordered from different vendors. In testing radio control of water heating, Southern California Edison found a 50 percent malfunction rate in receiver switches installed by electrical contractors. The "rebound effect" in these tests was great: a two hour interruption created a rebound of up to 12 times the normal load. The Project's conclusion was that radio control of water heating was not cost effective.

The Califiornia Project studied the relationship between duty cycle and load reduction in air conditioning. It was found that there must be 25 percent off-time before any load reduction can be observed. While load reduction is a direct function of the percent of off-time, customer willingness to participate lowers as off-time is increased. The best strategy appears to be to allow customers to select their own duty-cycle: even though load reduction is less with the shorter duty cycles, increased customer participation offsets the loss.

When the California Project tested voltage reduction as a conservation measure, energy consumption decreased. Tests of the effect of reduced voltage on appliances concluded that as long as voltage remained no lower than 114 volts there was no significant effect on appliance performance. When large scale implementation of voltage reduction began (as a result of the tests) different methods of control were employed. The end-of-the-line customer's voltage was used as the regulating feedback signal. Residential and commercial customers reduced their consumption but industrial and agricultural customers' response to voltage reduction varied. The program was highly successful and saved about 635 million kwh's in 1979.

CHAPTER FIVE : SUMMARY

Seven load management techniques were tested in the Projects: energy storage systems, appliance interlocks, timers, end-use improvements, ripple and radio controls, and controlled voltage reduction. There are a number of criteria by which these techniques can be compared. This report considers customer acceptance, difficulty in implementation, effectiveness in shifting or reducing electrical consumption, and cost.

To simplify the narrative, controlled voltage reduction (CVR) is treated separately from the other techniques: CVR is clearly a more effective conservation measure in many respects and it has very little in common with the other techniques.

Voltage reduction for conservation involves an adjustment in local feeder voltage regulation practices. Current procedures in setting local feeder voltages reflect past economies, when fuel costs for generating electricity were much lower. By reducing voltage to the low end of the range (acceptable to American engineering standards) the energy requirement of most electrical appliances in residences and commercial establishments is reduced without affecting their use.

Savings resulting from voltage reductions in the PG&E test were 635 million kwh. At a cost of 6.5¢ a kwh the savings was more than 41 million dollars. The cost of implementing the voltage reduction, $138,000, was minimal in comparison to the savings.

The utility experienced no significant problems in implementing voltage reduction. Customers also experienced few problems. One of the problems was that 230 volt motors were installed on 208 volt lines. These motors ran hot and had difficulty in starting.

Most customers seemed pre-disposed to favor conservation, and responded favorably to most of the efforts made by the utilities in the Projects.

End-use-improvements (retro-fit insulation) and energy storage systems required the greatest amount of customer participation. Retro-fit insulation was quite successful. This was due in part to the involvement of the utility in developing a program which assisted the homeowners in obtaining financing and qualified contractors to perform the installation. Utilities also offered inspections of the completed work and established standards and arbitration procedures involving disputes with contractors. This assistance involved considerable effort, and in some ways was comparable to establishing a franchise business.

Energy storage systems required a lot of customer involvement. The disruption to a household in installing these systems and their cost seem to have been enough to discourage homeowners from accepting the incentives offered by utilities for their installation. Difficulties connected with the Projects make it impossible to state any results except that the units remain unproven.

Less disruptive to customers were the radio and ripple systems and appliance interlocks and timers. All of these techniques involve installing a control on the customer's equipment, and consequently involve some common problems. There is a reluctance on the part of customers to tamper with electrical devices and they often blame failures subsequent to the installation on the switch. This is counter-balanced by the current mood favoring conservation. But educational efforts especially of air conditioning servicepersons and electricians is important in establishing and maintaining confidence in the switches. The controlling function of the switches is an inconvenience to the customers. In the case of timer switches for controlling swimming pool filters, this may be minimal. Two causes of problems are less customer confidence in the filtering action, and noise made by pumps running at night. Ripple or radio control of hot water heaters may make it necessary to plan dishwashing, laundry and bathing. Air conditioning controls will increase inside temperatures. The amount of increase that is tolerable depends in part on how much of a rate break is offered as an incentive for the installation of the switch.

Energy costs can be reduced in at least three ways: 1) by reducing the overall demand, 2) by improving the efficiency of energy use, and 3) by smoothing the fluctuations in consumption so that generating capacity is better utilized. Some of the techniques conserve energy in more than one way.

Energy storage systems were employed to shift demand from peak periods to off-peak. Physically the energy is the same but it is lower in cost since it is produced off-peak. Whether controlled by timers, radio, ripple, or part of an appliance interlock, siwtches primarily act to reduce peak load, but they may also reduce total load as a secondary effect. Controlled voltage reduction reduces energy consumption by increasing the efficiency of some uses and reducing the demand in others, by effectively derating the appliances or equipment to lower output levels. Due to the nature of the distribution network, however, this is somewhat more effective during off-peak than during peak periods.

Controlled voltage reduction would appear to be applicable to all utility systems. Costs are low and reductions in energy consumption are substantial. Other techniques may or may not have applications depending upon the character of the utility's load, fuel costs and other operational considerations. Control of water heaters by switches may not reduce energy consumption sufficiently to justify the expense in some areas. Summer peaking utilities will very likely find control of air conditioning to be financially feasible. Utilities with sharp daily peaks may find a mix of appliance interlocks in combination with timers or centrally controlled switches of value.

One implementation problem was far more troublesome than all others combined. Where the utilities were simultaneously involved in advancing the state of the art and implementation, the difficulty was insurmountable in most cases. The attempt to utilize a two way ripple system for load control in New Jersey was a failure. No problems with mature technology seriously delayed or impaired the success of the Projects, however.

Several Projects did have difficulties with various kinds of legal or industrial codes. Utility financing of retro-fit insulation became a constitutional question in the state of Washington. In attempting to oversee contractors practices it was found that there was no basis in fact for many of the building codes. Zoning code regulations restricting night time noise was a possible source of trouble in altering the time of use of swimming pool filters. In another Project the misapplication of voltage standards became a problem when manufacturers, contractors, and homeowners installed motors intended for one voltage level on equipment that was used at another voltage level.

Many of these problems resulted when legal codes were applied to changing circumstances. In the Projects, the potential legal problems were never actual barriers to implementation. The goal of energy conservation seemed to be helpful in securing favorable legal treatment.

Costs can be considered in a number of ways. One way is by point of application, i.e., by appliance controlled in ratio to resulting savings. Another way is by total cost per system. Controlled voltage reduction is low cost and requires little capital investment and a comparatively low operational expenditure.

Energy storage systems and end-use improvements require large capital investment per point installed and also per unit of energy saved. The cost per point can range in the thousands of dollars. Centrally controlled switches cost about $100 per point installed in typical systems. The operational budget is moderate, the cost per KW shifted from peak to off peak is two to three times lower than new peaking capacity. Appliance interlocks and timers cost between $40 and $100 and the cost of shifting is lower than that of centrally controlled switches.

Some of the problems with the various techniques were due to a lack of experience. But as more experience is gained the problems can be minimized and costs can be expected to decline. Most of the techniques tried were able to shift or reduce loads; some of them quite significantly.

APPENDIX 1

List of Electric Utility Demonstration and Pilot Implementation Project Participants

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List of Persons Interviewed

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TABLE 1A

Electric Utility Demonstration and Pilot Implementation Project Participants

Project Location	Participants	Performance Period	Key Project Personnel
Arizona	Solar Research Commission (s) Arizona Public Service Co. (u)	6/75-12/76[a]	James F. Warnock (SRC) Doug S. Windes (DOE)
Arkansas	Public Service Commission (s) Arkansas Power & Light Co. (u)	6/75-9/77	James F. Herden (APUC) Ralph Teed (AP&L) Doug S. Windes (DOE)
California	Energy Resources Conservation & Development Comm. (s) Public Utilities Comm. (s) Pacific Gas & Electric (u) San Diego Gas & Electric (u) Southern California Edison (u) Sacramento Municipal Utility District (u)	7/76-P	Richard Hairston (ERCDC) Roger Levy (ERCDC) John Flory (ERCDC) Jackalyne Pfannenstiel (Smith) (CPUC) formerly of Connecticut PUCA Doug S. Windes (DOE)
Connecticut	Public Utilities Control Auth. (s) Connecticut Light & Power (u)	6/75-3/77	Jackalyne Pfannenstiel (Smith) (PUCA)
Edmond, Oklahoma	City of Edmond (s) Edmond Municipal Electric Co. (u)	12/76-6/78	Paul Buntz (EO) Doug S. Windes (DOE)
Los Angeles, California	Department of Water & Power (u)	6/75-9/79	Dennis Whitney (LADWP) Doug S. Windes (DOE)
Michigan	Public Service Commission (s) Detroit Edison (u)	8/75-12/77	Robert Benko PSC Jane Christophersen (DOE)

(continued)

TABLE 1A (continued)

Location	Participants	Performance Period	Key Project Personnel
New Jersey	State Energy Office (s) Jersey Central Power & Light (u)	6/75-5/80	Charles Rickman (SEO) Paul Johnson (DOE)
New York	Public Service Commission (s) Consolidated Edison (u)	1/76-6/77	Joseph Rizzuto (PSC) Doug S. Windes (DOE)
North Carolina	Utilities Commission (s) Carolina Power & Light (u) Blue Ridge Electric Membership Corporation (u)	7/76-8/79	Antoinette Wike (NCUC) Jane Christophersen (DOE)
Ohio	Public Utilities Commission (s) Dayton Power & Light Co. (u) Toledo Edison Co. (u) Buckeye Power Co., (u)	6/75-3/78	Robert Wayland (PUC) Jane Christophersen (DOE) Joseph Wathen (PUC)
Puerto Rico	Commonwealth (s) Water Resources Authority (u)	7/76-7/80	Alberto Bruno-Vega (C) Paul Johnson (DOE)
Rhode Island	Public Utilities Commission (s) Blackstone Valley Electric Co. (u)	7/76-10/78	Thomas Chmura (PUC) Lewis Bailey (BVEC) Christina VanSickle (DOE)
Vermont	Public Service Board (s) Green Mountain Power Co. (u)	11/74-1/77	Wayne Foster (PSB) Charles Elliott (GMPC) Larry Kaseman (DOE) Doug S. Windes (DOE)

(continued)

TABLE 1A (continued)

Project Location	Participants	Performance Period	Key Project Personnel
Washington	State Energy Office (s) Seattle City Light (u) Clark County PUC Puget Sound Power & Light Co. (u)	9/76-10/78	Jacob Fey (SEO) Nancy Tate (DOE)
Wisconsin	Public Service Commission (s) Wisconsin Public Service Corp. (u)	9/75-11/80	James Simpson (PSC) Richard E. James (WPSC) Jane Christophersen (DOE)
	PILOT IMPLEMENTATION PROJECTS		
California	Energy Resources Conservation and Development Commission (s)	10/77-12/82	Richard Hairston (ERCDC) Doug S. Windes (DOE)
Connecticut	Public Utilities Control (s)	10/77-9/82	C. T. Caprina (PUCA)
Grand River Dam Authority	Grand River Dam Authority (u)	10/77-9/79	Jerry Taylor (GRDA) Jane Christophersen (DOE)
Iowa	Iowa State Commerce Commission (s)	10/77-9/80	Robert J. Latham (ISCC) Jane Christophersen (DOE)
Minnesota	Department of Public Service (s)	10/77-9/82	Larry Anderson (DPS) Paul Johnson (DOE)
Springfield, Missouri	City Utilities of Springfield (u)	10/77-1/80	John L. McMahan (CU) Jane Christophersen (DOE)

(continued)

TABLE 1A (continued)

Project Location	Participants	Performance Period	Key Project Personnel
North Carolina	North Carolina Utilities Comm. (s)	10/77-10/82	Andrew W. Williams (NCUC) Jane Christophersen (DOE)
Ohio	Public Utilities Commission (s)	10/77-3/81	John Borrows (PUCO) Jane Christophersen (DOE)
South Dakota	South Dakota Public Utilities Commission	10/77-3/78[d]	Joe Norton (SDPUC)
Seattle, Washington	Seattle City Light (u)	10/77-9/82	Robin Calhoun (SCL) Nancy Tate (DOE)

Source: Compiled from Electric Utility Demonstration and Pilot Implementation Project Reports and documents and interviews, 1975-1980.

[a]Project was completed as far as DOE involvement was concerned. The experimental TOU rates have continued to date.

[s]Participating state or city agency.

[u]Participating utility.

[d]Project terminated.

TABLE 2A

List of Persons Interviewed

Name	Address
Department of Energy Personnel	
M. Larry Kaseman	U.S. Department of Energy Economic Regulatory Administration Division of Regulatory Assistance Washington, D.C.
Steven Mintz	"
Gary Selnow	"
Project Participants and Consultants	
George Brazil	Arkansas Power and Light Little Rock, Arkansas
David Bryant	"
Charles Elliott	Green Mountain Power Company Burlington, Vermont
Paul Hart	Arizona Public Service Company Phoenix, Arizona
Cathleen F. Meyer	City Utilities of Springfield Springfield, Missouri
Steve Reynolds	Pacific Gas and Electric Company San Francisco, California
Jerry Taylor	Grand River Dam Authority Vinita, Oklahoma
Byron Tomilson	Pacific Gas and Electric Company San Francisco, California
Billy J. Yarborough	Carolina Power and Light Raleigh, North Carolina

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