MASTER

FACTORS AFFECTING THE POTENTIAL OF
DIRECT LOAD CONTROL
FOR
NON-GENERATING UTILITIES

FINAL REPORT

MANUSCRIPT COMPLETED: JANUARY 1979
DATE PUBLISHED: APRIL 1979

Volume I

prepared for :

ELECTRIC ENERGY SYSTEMS
DEPARTMENT OF ENERGY

CONTRACT NO. EC-76-C01-2099

Gilbert/Commonwealth

ENGINEERS/CONSULTANTS Reading, PA/Jackson, MI

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

27
8/7/79
240 NTIS
ENERGY

TECHNOLOGY

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

Printed in the United States of America. Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road, Springfield, Virginia 22161
Price: Printed Copy \$9.25; Microfiche \$3.00

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, contractors, subcontractors, or their employees, makes any warranty, express or implied, nor assumes any legal liability or responsibility for any third party's use or the results of such use of any information, apparatus, product or process disclosed in this report, nor represents that its use by such third party would not infringe privately owned rights.

**FACTORS AFFECTING THE POTENTIAL OF
DIRECT LOAD CONTROL
FOR
NON-GENERATING UTILITIES**

FINAL REPORT

**MANUSCRIPT COMPLETED: JANUARY 1979
DATE PUBLISHED: APRIL 1979**

Volume I

NOTICE

This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the United States Department of Energy, nor any of their employees, nor any of their contractors, subcontractors, or their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness or usefulness of any information, apparatus, product or process disclosed, or represents that its use would not infringe privately owned rights.

prepared for:

**ELECTRIC ENERGY SYSTEMS
DEPARTMENT OF ENERGY**

CONTRACT NO. EC-76-C01-2099

Gilbert/Commonwealth

ENGINEERS/CONSULTANTS Reading, PA/Jackson, MI

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

TABLE OF CONTENTS

VOLUME I

Table of Contents

List of Exhibits

Preface

- Section I - Introduction
- Section II - Potentially Controllable Loads
- Section III - Characteristics of Controllable Loads
- Section IV - Control Strategy
- Section V - Distribution System Analysis
- Section VI - Communication and Control System:
Description and Cost Considerations
- Section VII - Physical Distribution System Factors
- Section VIII - Economic Evaluation Methodology
- Section IX - The Impact of Wholesale Rate Structure
- Section X - Summary - A Procedural Outline

Bibliography

VOLUME II

- Appendix A - Case Studies - Load Control Simulations of
Four Utilities
- Appendix B - Load Research - Water Heaters and Central Air
Conditioners
- Appendix C - Local Logic Devices - A Survey

LIST OF EXHIBITS

- Exhibit I - 1 Utilities Presently Sponsoring Communication and Load Control System Tests
- Exhibit II - 1 Residential Appliance Survey
- Exhibit II - 2 Residential Appliance Survey - Calculation of Controllable Load
- Exhibit II - 3 Approximate Average Water Use of Major Crops Irrigated
- Exhibit III- 1 Water Heater Diversified Demands - Winter Curves
- Exhibit III- 2 Water Heater Diversified Demands - Typical Summer Curves
- Exhibit III- 3 The Time Varying Nature of Diversified Demand
- Exhibit III- 4 Water Heater Restore Curves
- Exhibit III- 5 Central Air Conditioner Diversified Demand - Typical Summer Curve
- Exhibit III- 6 Central Air Conditioner Peak Day Load Curves
- Exhibit III- 7 Air Conditioner Demand vs. Temperature Curves
- Exhibit III- 8 Central Air Conditioner Load Control Test - Payback Period, LR AFB, Sept. 2, 1975
- Exhibit III- 9 Central Air Conditioner Load Control Test - Payback Period, Arkansas P&L, Aug. 13, 1975
- Exhibit III-10 Space Heater Peak Day Load Curves
- Exhibit IV - 1 Substation vs. System Comparison of Peak Occurrences

LIST OF EXHIBITS

Page 2

- Exhibit V - 1 Diversified Demand Curve: Winter Peaking Rural Utility
 Residential With Water Heating
- Exhibit V - 2 Diversified Demand Curve: Winter Peaking Rural Utility
 Residential - All Electric
- Exhibit V - 3 Diversified Demand Curve: Summer Peaking Rural Utility
 Residential With Water Heating
- Exhibit V - 4 Diversified Demand Curve: Summer Peaking Rural Utility
 Residential - All Electric
- Exhibit V - 5 Summer Peaking Rural System
 Summary of Restore Effects - Worst Case Section
- Exhibit V - 6 Summer Peaking Rural System
 Summary of Restore Effects
- Exhibit V - 7 Winter Peaking Rural System
 Summary of Restore Effects - Worst Case Section in
 Each Feeder
- Exhibit V - 8 Winter Peaking Rural System
 Summary of Restore Effects
-
- Exhibit VI - 1 Typical Distribution System Makeup
- Exhibit VI - 2 V.H.F. Radio Control
- Exhibit VI - 3 V.H.F. Radio Control Components
- Exhibit VI - 4 L.F. Powerline Carrier Control
 Medium Voltage Injection
- Exhibit VI - 5 L.F. Powerline Carrier Control Components
- Exhibit VI - 6 L.F. Powerline Carrier Control
 Transmission Voltage Injection
- Exhibit VI - 7 L.F. Powerline Carrier Control Components
- Exhibit VI - 8 H.F. Powerline Carrier Control
 Line or Substation Injection
- Exhibit VI - 9 H.F. Powerline Carrier Control Components

LIST OF EXHIBITS

Page 3

Exhibit VI-10	Hybrid Control Radio Plus H.F. Powerline Carrier
Exhibit VI-11	Hybrid Control Components
Exhibit VI-12	Telephone Address Control
Exhibit VI-13	Telephone Address Control Components
Exhibit VII-1	Influence of Bulk Supply Arrangements on the Communication Path
Exhibit VII-2	Benefit/Cost Analysis Flow Diagram
Exhibit VIII-1	Benefit/Cost Analysis Flow Diagram
Exhibit VIII-2	2-Way Load Control System - Ancillary Function Evaluation
Exhibit IX-1	Impact of Wholesale Power Rates on Load Control Benefits

PREFACE

Through load management the patterns of electric energy supply and use can be modified to improve the production and delivery of electric energy. The objectives of load management are to:

- o Improve the efficiency as well as the utilization of generation, transmission and distribution systems.
- o Shift fuel dependency from limited to abundant energy sources.
- o Lower the reserve requirements of generation and transmission capacity.
- o Improve the reliability of service to essential loads.

Several alternatives are available for achieving Load Management, including direct or voluntary control of customer loads, customer or utility energy storage systems for diurnal load shifting, and expanded interconnection and operation of electric power systems. All of these alternatives are available to the fully integrated (generating, transmitting and distributing) electric utility and the analysis of their effects encompasses the power supply and delivery system. However, the costs and benefits of the alternatives to the fully integrated electric utility are perhaps not so obvious. Therefore, by considering a non-generating utility, the analysis will focus upon the distribution system and wholesale power supply interaction as a step toward an analysis including the power supply and delivery system.

This report develops an analysis procedure and discusses some of the relevant factors to be considered in the application of direct load control for a non-generating utility system.

The analysis concentrates on the distribution system only to determine the effect of rates and payback as a result of direct load control. Thus, the study is responsive to the specific needs of the non-generating utility. This

analysis of direct load control encompasses the determination of those loads amenable to control, the selection of a suitable one-way communications system to send control and the estimation of expected benefits and costs. The complementary functions to the application of direct load control such as automatic meter reading via the addition of a bi-directional communications system and voltage control are not included in the analysis but are detailed for future consideration. Based upon the analysis developed herein, a reasonable assessment of direct load control can be made by the non-generating utility and the foundation formed for consideration by generating utilities.

SECTION I

INTRODUCTION

The Department of Energy has developed a comprehensive program for assisting the electric power industry in the evaluation of new energy alternatives. An important segment of this program concentrates on developing means for better managing the peaks of electric utilities. This segment falls under the generic title of Load Management.

Load management is often divided into "use management" and "supply management." Use management is the direct and voluntary control of selected loads of end-use customers. Supply management, on the other hand, concentrates on increased coordination of the planning and operating needs of utilities to insure the availability of capacity. Use management can be accomplished through four primary functions: (a) price control through rate structure, (b) voluntary load management by customers, (c) customer storage devices, and (d) direct mechanical control. This report deals exclusively with the direct mechanical control.

In recent years, a wide variety of communication and control systems have been developed for the purpose of direct control of the end use customer loads. Significant experiments of direct utility control systems have been conducted by utilities of various sizes. Exhibit I-1 identifies the load control experiments under way as of November 1978. The results of the demonstration projects have proven the technical merits of various generic types of load control systems developed for utility applications.

Given the technology of direct utility load control, it is important to evaluate the potential of applying load control technology to specific utility systems on the basis of the estimated cost as well as the potential benefits in such areas as reducing spontaneous load requirements, minimizing the risks of capacity shortages and providing the ability to shed loads during periods of emergency. In this Report, the non-generating utility was selected to

demonstrate the effects of load control technology. The use of non-generating utility permits a simpler quantification of costs and benefits associated with each system; it isolates the load control effect on rates and payback requirements by avoiding the generation considerations and the analysis requirements for hierarchical generation, transmission, and distribution system configurations.

The sections that follow outline the general approach used to assess the potential application of generic types of control equipment. Other chapters of the Report describe the major types of controllable load, and the system and operational characteristics of various control and communication systems. In addition, cost and benefit analyses were conducted to indicate the economic feasibility of applying control equipment under various load and system configurations representative of non-generating utilities.

In evaluating load control systems and their potential applications for utilities of various load characteristics, several major tasks were required. Broadly defined, the present study included the following tasks:

1. Analyze customer and load characteristics of the utility; and identify the controllable load.
2. Characterize the control and communication systems that are commercially available.
3. Optimally match load control system characteristics to utility system characteristics.
4. Interview utility operation personnel for actual experience to testing and implementing load control systems.
5. Select several utilities with different load and system characteristics as the basis of assessing the potential application of control systems.
6. Estimate the benefits and costs of applying load control equipment.

7. Develop benefit/cost ratios, payback period, and other indicators to determine the economic feasibility of applying load control systems to privately and publicly owned utilities as well as member-owned cooperatives.

The methodology utilized in this Report to identify the control systems most suitable for a particular utility should be placed in the context of general guidelines and not a rigid procedural manual. This point is important because of the very nature of the utility system. It is difficult to "typify" the distribution utility in terms of its physical system, customers, and supply arrangements. Public, member, and privately-owned systems reflect different cost components. Physical location, climatic region, and other environmental and regulatory differences, all place a unique characterization on any individual utility.

Therefore, a utility conducting its own evaluation of the potential of applying control equipment should first establish the objectives of controlling load. These objectives will set the scope of the analysis, and outline the required tasks. The outline of equipment parameters will actually follow if objectives are clearly defined. If the main purpose, for example, is to provide the ability to shed selected loads during periods of emergency, then the rate of speed of the transmission signal and the signal integrity may be more important factors to consider in the selection of the type of equipment than the benefit/cost ratio associated with the use of the equipment. If, on the other hand, the sole objective is that of lowering the demands at peak periods and thus cutting purchased power costs, then the investigation should be limited to the one-way load control systems. In any event, the primary objectives should represent conditions dictating the criteria for selecting appropriate equipment and communication paths for a utility.

Section II through VIII of this Report provide more detailed descriptions of the tasks outlined above and the analyses required for each task. Section IX provides some qualitative assessment of the potential impact of wholesale rate structures on load control programs. Section X summarizes in outline form the

results of the analysis and provides a set of steps that may be followed by non-generating utilities in gathering and analyzing data and in assessing the potential cost and benefits of load control programs. In addition to the technical analyses of distribution systems and load control equipment, four types of utilities were used to characterize the applications of various generic types of control systems. In each utility scenario, 5 basic communication and control systems were compared:

1. Radio
2. Low Frequency Power Line Carrier - Rythm Keying
3. Low Frequency Power Line Carrier - Multibit Coding
4. High Frequency Power Line Carrier - 1 way
5. Hybrid - Radio/Power Line Carrier

The Telephonic and direct wire systems were not treated in this cost/benefit analysis because of 1) the absense of any standardized cost or equipment ownership criterion, and 2) the "breadboard" characteristics of direct wire systems.

High Frequency Power Line Carrier 2 way systems were not treated because of their severe economic disadvantages when a comparison is made strictly on the function of direct load control.

The Case Study results are provided in Appendix A, the Case Studies Section of the Report.

Personal interviews with the personnel of several operating utilities testing or implementing load control systems provided extremely valuable information which has been integrated into this report. These utilities, as well as the many sources of industry data related to load control which were used for reference in this study, are listed in the bibliography.

EXHIBIT I-1UTILITIES PRESENTLY SPONSORING
COMMUNICATION AND LOAD CONTROL SYSTEM TESTS

<u>UTILITY</u>	<u>TYPE*</u>
American Electric Power	PLC-HF
Arizona Public Service	R
Arkansas P & L	R
Buckeye Power	R
Carolina P & L	PLC-HF, R
Central Illinois Light	R
Central Maine Power	R
Central Vermont PS	PLC-LF
City of Burbank	TM
Cobbs County Elect Memb Coop	R
Consolidated Edison (NY)	PLC-LF
Consumers Power	PLC-LF
Dayton P & L	R
Delmarva P & L	PLC-HF
Detroit Edison	R
Duke Power	PLC-HF, R
GPU Service Corp	PLC-HF
Georgia Power	H
Gree Mountain Power	PLC-LF
Kansas Electric Coop	R, LL
Long Island Lighting	R
Lumbee River Elec Memb Coop	R
Minnkota Power Coop	PLC-LF
Mississippi P & L	PLC-LF
Nebraska PPD	PLC-LF, R, LL
Northeast Utility Service	PLC-HF
Northern States Power	R
Omaha PPD	T
Otter Tail Power	R
Pacific G & E	PLC-HF, R
Philadelphia Electric	PLC-HF
Potomac Edison	LL
Public Service E & G	LL
San Diego G & E	PLC-HF
Southern California Edison	H
Sulphur Springs Valley Elec Coop	R
Wisconsin Electric Power	PLC-HF
Wisconsin P & L	PLC-LF

*PLC-LF = Power Line Carrier - Low Frequency

PLC-HF = Power Line Carrier - High Frequency

R = Radio

LL = Local Logic

H = Hybrid

TM = Telemetry

T = Telephone

SOURCE: Electrical World, 'Load-Management Studies Top 100 Mark',
November 1, 1978 page 57.

SECTION II

POTENTIALLY CONTROLLABLE LOADS

Any benefits to be gained from the application of a direct load control program by an electric utility are dependent on the cooperation of end-use customers having the types of loads that are controllable. In order to estimate the load control potential, it is necessary to determine which customers have controllable loads and the associated load density related to the distribution system.

In principle, in order for load control application to be cost justified, the load contemplated for direct utility control should represent a sufficiently large amount of deferrable KW demand. The more knowledge available to the utility on the usage pattern and load characteristics of end-use equipment, the greater the confidence level that can be given to expected kW reductions as a benefit from control. In addition, due consideration should be given to the usage patterns of the appliances. In general, some types of storage medium for the appliance's output (e.g., heat) should exist so that the interruption will only cause minimum inconvenience to the customers.

Appliance saturation in the service area and customer usage patterns will vary from utility to utility. In order to provide needed information as to the nature, extent and density of different types of customers with loads having a potential for control, a current assessment of these factors is necessary.

1. Residential Appliances

In general, temperature-sensitive residential appliances dictate the time and intensity of the peak periods of most non-generating electric utilities because of the size of the load and low diversity. Significant results have been recorded by utilities effecting direct control of selected temperature-sensitive appliances of the residential customers. Specifically, the contribution of a residential water heater or air conditioner in the form of a deferrable kW demand has enabled many utilities to pursue full implementation plans of load control.⁽¹⁾

Other household appliances may also have the end-use characteristics that would suggest load control application. Several concerns, however, may restrict the adaptability of such highly visible appliances as washers, dryers, or freezers to an acceptable control logic:

- a. The requirements of a working couple for a fixed time of use.
- b. The higher diversity present in the collective use of those appliances by other customers in the distribution system yielding a lower deferrable KW demand during potential control periods.
- c. Electrical wiring cost per appliance imposed on the utility.
- d. Legal implications facing the utility concerning liability in the event of appliance malfunction.

To obtain the best possible result of load control, a survey of residential customers in the service area should be conducted to determine appliance saturations, customer density on the distribution circuits, and customer acceptance to utility control. For many distribution utilities, a current knowledge of these customer parameters is not readily available. The survey represents an expedient method for gathering the needed information.

Exhibit II-1 summarizes the results of an actual customer survey performed in July and August of 1978. The data was collected from residential customers of a summer peaking rural cooperative with a maximum demand of approximately 31 MW. As indicated in the exhibit, farm houses were the predominant residence and central air conditioners the predominant electric appliance available for control. The summaries shown in the exhibit provide a convenient format to identify the types of residence and controllable appliances. One suggested format for calculating controllable load is provided in Exhibit II-2.

EXHIBIT II-1

RESIDENTIAL APPLIANCE STUDY

DETAIL OF RESULTS FOR:

TOTAL NUMBER OF SURVEYS MAILED OUT: 5334
 PERCENT OF SURVEYS RETURNED: 44.54%
 TOTAL NO. OF RESIDENTIAL CUSTOMERS: 6657

RESIDENT DESCRIPTION	SINGLE FAMILY	MOBILE HOME	APARTMENT	FARM HOUSE	BUSINESS & RESIDENCE COMBINED	OTHER	
TOTAL NO. OF RESPONDING CUSTOMERS	607	616	18	825	29	239	
PERCENTAGE REPORTING EACH TYPE OF RESIDENCE	25.55%	25.93%	0.76%	34.72%	1.22%	10.06%	
ESTIMATED CUSTOMERS BY RESIDENCE TYPE	1362	1382	40	1852	65	536	
ELECTRIC APPLIANCE	WATER HEATER	--AIR CONDITIONING-- CENTRAL	WINDOW	CLOTHES DRYER	---SPACE HEATING--- FORCED AIR FURNACE	HEAT PUMP	OTHER
TOTAL NO. CUSTOMERS REPORTING APPLIANCE	1102	802	1724	1212	389	77	351
PERCENTAGE REPORTING EACH TYPE OF APPLIANCE	46.36%	33.75%	72.56%	51.01%	16.37%	3.24%	14.77%
ESTIMATED APPLIANCES BASED ON SURVEY	2473	1800	3870	2720	873	172	787
NUMBER OF RESPONDING CUSTOMERS GIVING SIZE OF APPLIANCE	1033	656	977		40	53	
	AVERAGE TANK SIZE	AVERAGE TON CAPACITY	AVERAGE UNITS/SIZE		AVERAGE SIZE	AVERAGE TON CAPACITY	
	33.98	3.05	15635.67		78001.87	3.37	

EXHIBIT II-1

Page 2 of 2

NON-ELECTRIC APPLIANCE	GAS WATER HEATER	OTHER WATER HEATING	GAS SPACE HEATING	OTHER SPACE HEATING
TOTAL NO. CUSTOMERS REPORTING APPLIANCE	1245	8	859	202
PERCENTAGE REPORTING EACH TYPE OF APPLIANCE	52.53%	0.34%	36.15%	8.50%
ESTIMATED APPLIANCES BASED ON SURVEY	2801	17	1928	453

EXHIBIT II-2

RESIDENTIAL APPLIANCE SURVEY

DETAIL OF RESULTS FOR:

Calculation of Controllable Load:

Summer Season	<u>Water Heating</u>	<u>Central Air Conditioning</u>	<u>Other</u>	<u>Total</u>
Number of Appliances	2,473	1,800	-	
Times				
Controllable Load per Appliance	.6	1.0	-	
Times				
Loss Factor	1.176	1.176	-	
Equals Controllable Load	1,745	2,117	-	3,862
Winter Season	<u>Water Heating</u>	<u>Space Heating</u>	<u>Other</u>	<u>Total</u>
Number of Appliances	2,473	-	-	
Times				
Controllable Load per Appliance	.8	-	-	
Times				
Loss Factor	1.176	-	-	
Equal Controllable Load	2,327	-	-	2,327

As indicated above, the residential loads considered to have the highest potential for load control are those appliances which are sensitive to temperature and are associated with some heating/cooling storage medium.

The following paragraphs characterize three such residential appliances and provide some assessment on the load control potentials.

a. Water Heater

The storage characteristics of water heaters inherent in their design make control by the utility relatively easy to accomplish with little, if any, inconvenience to the customer⁽²⁾.

For most winter peaking utilities and some summer peaking utilities, control of an electric water heating load can represent a significant reduction in load. The quantification of kW of deferrable demand per water heater (deferrable at times of the utility's peak periods, for example) is dependent on several factors:

1. Capacity of the appliance (number of gallons).
2. Type and size of heating elements.
3. Season of application.
4. Climatic characteristics of the service area.
5. Time of day of the control periods.
6. Saturation of the appliance.

A detailed summary of the available industry data reported on water heating tests is provided in Appendix B. The range of test results of the reporting utilities for winter or summer application is quite wide. However, an analysis of the results of two recent water heating tests⁽³⁾ indicate the following range of diversified demand per water heater during evening winter peak hours of 6-7 p.m. and summer peak hours between 3 p.m. and 6 p.m.

Winter	-	0.60 to 1.70 kW
Summer	-	0.47 to 1.39 kW

In the absence of actual test data, the following minimums may be reasonably applied for the purposes of establishing a conservative estimate for calculating the potential benefit from controlling water heaters.

Winter	-	0.80 kW
Summer	-	0.60 kW

A more refined estimate may be possible by examining Appendix B or other available sources of water heater load research data for utilities, geographic areas, and other factors which may be comparable to the non-generating utility.

b. Central Air Conditioning

For summer peaking systems, the influence of air conditioning on the peak of the utility makes it an obvious choice to consider for direct control. Window air conditioning units, however, tend to be relatively small in size, more portable, and possibly greater in diversity during control periods when compared to central air conditioning units. In addition, electrical wiring problems are possible in cases where a unit is being supplied power from an already heavily loaded house circuit. Thus, for most applications, the benefit can only be expected from central air conditioning control.

The major factors that may affect the potential load reduction from the control of central air conditioning units are listed below. More detailed analyses of these factors is provided in Section III of this report.

1. Individual maximum kW demand per unit (or connected load if the maximum demand is unknown).
2. Climatic characteristics of the service area.

3. Time of day of the control periods.
4. Saturation of the appliance.
5. Length of the control periods.

An investigation was made on the available load research data concerning central air conditioning reported by utilities, and the results are summarized in Appendix B. The findings of recent load research tests and direct load control programs indicate that a diversified demand per residential central air conditioner of over 4 kW can be considered a reasonable approximation for summer peaking conditions.⁽⁴⁾ This demand represents between 80% and 90% of the estimated average connected load. However, in order to control central air conditioning units in a manner that will have a minimum discomfort to the customer, the method of control should encompass some form of a shared control cycle which utilizes the volume of the house as a cooling storage medium. In current load control programs only the low voltage thermostat circuit is controlled to inhibit the compressor, which allows the inside fan motor to continuously circulate air and thereby contribute to customer acceptance.⁽⁵⁾ For example, if one-fourth of the central air units were controlled at any given time, the effect of a 4 kW average demand per central air unit on the system time of peak demand would be 1 kW.

c. Central Heating Units

Most U.S. utilities, to this date, have not conducted or emphasized load management programs which involve the control of existing electric heating. As of 1978, there has been little research of a sufficient magnitude conducted to assess the practicality and economic feasibility of controlling existing space heating schemes (without modification). A preliminary study has indicated that as much as

7 kW per electrically heated home could be deferred by controlling the existing heating system during peak winter hours.⁽⁶⁾ Temperature drops inside the home in the study averaged 1.75°F per hour of continuous off-time (no cycling). While these results are promising, more research and experimental programs are needed to determine the potential amount of control considered possible for these appliances, given temperature, house construction, demographic characteristics, and a control constraint of minimizing the inconvenience and discomfort to the customer. A control strategy, similar to the shared cycling scheme which has been quite successful with central air conditioners, needs to be developed and fully tested before the feasibility of centralized control of existing U.S. space heating systems as a viable load management technique can be determined.

The potential of controlling space heating load can be enhanced with the use of some non-conventional types of heating system:

Storage type space heating - This type of heating has been popular in Europe for many years. After an 8-12 hour charge (on-time) these systems can normally supply enough heat for the remainder of the day. The on time is short enough such that these systems can be supplied completely off-peak, usually at night. One significant drawback to this charging cycle has become apparent in European domestic applications of such heating systems. The discharge of stored heat occurs in inverse proportion to its demand. The maximum heat is available in the hours immediately following completion of the charging cycle. However, the demand for heat throughout the morning hours is somewhat reduced when members of the household are absent because of routine daily activities. In the early evening hours as temperatures drop and households require more heat, the minimum is available from the storage system. These factors may limit the application of such appliances in severe winter

climates. There is currently very little use of storage heating in this country, and it is unlikely that the great majority of utility customers would be willing to make an investment in such a system until there are reasonable economic incentives coupled with a thorough consumer education program. Several northern utilities currently are offering incentive rates to promote this type of heat,⁽⁷⁾ so perhaps in the next several years significant number of storage space heaters will be available for centralized control in certain areas of the country.

Dual Fuel Systems - Specially modified heating systems have been developed to run on electricity during the utility's off-peak periods and then switch to an alternate fuel source during peak periods, thus moving their heating usage of electricity completely off-peak. These dual fuel heating systems are becoming increasingly popular in some areas. A minimum investment is required for the conversion and fuel expenses can be significantly reduced.⁽⁸⁾ Where low off-peak rates are offered, such a system could have a payback of as little as two years.⁽⁹⁾

In summary, because of the relationship to temperature and peak periods, the high kW of connected load, and the availability of storage mediums, residential space heating is potentially the prime candidate for centralized load control by winter peaking utilities. In the short term, ongoing tests may show that cycling of existing heating systems will provide a means of deferring load to off-peak periods. In the long term, storage heat systems and dual fuel systems offer the highest potential for load deferral for winter peaking utilities.

2. Irrigation

The most successful application of utility control of agricultural loads has been in the control of irrigation pumps. Certain types of irrigation systems (particularly the center-pivot and other sprinkler systems) incorporate watering techniques that, by design, would permit controlled operation. In addition, depending on the acceptable level of soil moisture depletion associated with various soil types and the crops grown, some irrigation systems may tolerate part-time operation. Significant progress has been made in refining the technology of applying irrigation control and in gaining acceptance by irrigators.⁽¹⁰⁾

In Nebraska and northwest Kansas, several years of effort by public power districts, cooperative utilities, the Department of Agriculture, and local agricultural engineers have fostered irrigation control strategies for part-time operation, corresponding to the time of the peak requirements of the utility. Reports on the progress of these efforts indicate that, depending on soil conditions or crop requirements, not all irrigation systems will permit a part-time operation.⁽¹¹⁾ Flood watering techniques for example, may offer a potential for scheduled operation on a calendar day basis that would not allow for interruption of the flooding cycle.

Quantification of the load reduction associated with the deferment of irrigation loads during peak periods of the utility requires substantial analyses. Some of the factors which should be considered in such an analysis include types of irrigation system, total irrigation horsepower, underground water supplies, crops, soils, rainfall, frequency and duration of peak loads requiring control, and customer acceptance. It is not necessarily true that every utility serving irrigation loads, even sprinkler systems, will find a sufficient amount of deferrable load from irrigation at the time of the peaks to be controlled.

Since the peak water use of all crops does not occur at the same time, there is some diversity of demand associated with irrigation load. The amount of this diversity for a given utility will depend on the percentage of electrically powered irrigation pumps used for the various crops in its service area. Some typical crop water use curves are provided in Exhibit II-3. Certain types of crops may have critical stages of growth. The possible reductions in yield caused by the inadequate supply of water during the critical growing period tend to limit the potential for load control.

Some knowledge of soil types is also an important factor in determining the load control potential. Control can be exercised more often in soils which can store moisture, particularly during periods of little rainfall. Clay and loam soils fall in this category, while sandy soils store much less moisture. The frequency and duration of load control on sandy soils is therefore more limited.

The potential for load control also depends on the type of irrigation system. Center pivot systems offer the least problems to load control since such systems automatically resume irrigation following control. With a side roll system, the control cycle will not affect the total water applied, but the time required to irrigate will be increased. If gravity or surface systems are controlled during an irrigation set, excessive watering might occur in the upper field. Therefore, the control strategy for the gravity system must be limited to regularly scheduled intervals. The effects of load control can be offset by installing automatic restarting equipment to use the allotted time during peak water use periods.

The specific load curves of irrigation loads should be examined relative to the total non-generating utility's load profiles for those periods when load control would likely be implemented. The most convenient method of obtaining such load curves would be from circuit feeders or substation readings.

EXHIBIT 11-3
APPROXIMATE AVERAGE WATER USE OF MAJOR CROPS IRRIGATED

In addition, the load control program should probably be initiated with larger irrigation loads, to achieve the maximum benefit per control point. As a general rule, one horsepower of irrigation pumping could be equated to one kW of load at the control point because of electromechanical inefficiencies and line loss.

The following points summarize the factors affecting the potential for control of irrigation load.

1. Frequency and duration of control periods relative to peak irrigation loads.
2. Irrigation system types.
3. Soils and their moisture holding capability.
4. Peak water use periods of crops.
5. Amount of rainfall.
6. Size of individual irrigation pumps.
7. Customer acceptance and understanding.

3. Commercial and Other Industrial Loads

Most of the utility direct load control has, so far, focused on selected residential loads. For industries, local logic devices have been utilized to balance equipment loadings for the purpose of lowering the maximum billing demands. Detailed analyses of self contained load control and load limiting devices are provided in Appendix C.

Direct utility control of commercial and industrial end-use loads has not yet been implemented on a large scale. Although industrial customers in general are interested in exploring the possibility of direct utility control, how successful the application of control technology will be in industry remains to be seen. It is apparent that nonproduction loads can be controlled to the benefit of both the utility and industry without affecting production. On the other hand, if the industrial's power bill is only a small portion of total product cost, or if plant inefficiencies

or labor force restrictions are imposed, it is likely that a load control program will not be well received. Before the load control potential can be quantified, the utility must work closely with the industrial customer to analyze the load characteristics of equipment and processes and the effect of those loads on the utility's peaking requirements, and target potentially controllable loads for further study. As in the case of residential customers, economic (rate) incentives will likely be necessary for industries to accept direct utility control.

Commercial customers are perhaps the most sensitive customer group to consider for load control application. As in industry, a few major hotel chains and other types of commercial customers have installed local logic devices for load leveling to reduce billing demands. But a majority of the customers in this sector are extremely conscious of the comfort requirements of their customer (from shopping centers and malls to office buildings and hospitals). Reducing costs and improving operating efficiencies are considered important only to the extent that they do not interfere with customer convenience or service standards. Other specific problem areas for load control in the commercial sector include the following:

- a) leased space in commercial buildings where the wiring does not permit practical selective control, or master metering prevents a required rate incentive.
- b) mobile home communities served as commercial customers, because of the nature of the load.

However, since the largest loads of the commercial customers are the temperature sensitive appliances, potential does exist for control. As with industry, the utility will need to work closely with the commercial customer to inventory and analyze the equipment and appliances, and develop an acceptable interruption procedure.

CHAPTER II - Footnotes

1. Charlie F. Jack (Buckeye Power), "Peak Shaving a Way to Fight Rising Costs", 1975 Rural Electric Power Conference. Omaha, Nebraska, April 27-29, 1975 (C75-310-8-IA).

James B. Oliver (Detroit Edison), "Radio Control of Water Heaters and Distribution Station Voltage Regulators". 1969 IEEE Summer Power Meeting. Dallas, Texas June 22-27, 1969 (pp 666 - PWR).

Paul E. Weatherby (Cobb EMC), "Load Management Report". 1977 Managers Conference. Kansas City, Missouri August 11, 1977 (#6a).
2. Robert L. Roberts (Pioneer R.E.C.). "Load Factor Improvement Through Radio Controlled Diversity". 1973 Rural Electric Power Conference. Minneapolis, Minnesota April 30-May 1, 1973 (c-73-906-51A).
3. See Appendix I, Abstract of Houston Lighting and Power Company. Central air conditioning study and Consumers Power Company water heating study in the 1974-1975 and 1975-1976 (respectively). Report of the Load Research Committee of the A.E.I.C.
4. Arkansas Power and Light Company, "Peak Load Control Study, Summer of 1975." Distribution Standards Section. Arkansas Power and Light Company October 6, 1975. Rev. January 12, 1976.
5. Ibid
6. "Demand Controller Shaves Winter Peak", Electrical World, October 1, 1956, pp. 92, 93.
7. Policy Bulletin No. 20-2.1, P.J.M. Electric Cooperative, Inc., Warren, Minnesota. August, 1978.
8. Highline Notes, Cass County Electric Coop, Kindrad, North Dakota. August, 1977.
9. Ibid
10. L. E. Stetson and Ivan D. Nelson, "Irrigation Scheduling to Control Electrical Demand". Nebraska Irrigation Short Course. January 20-21, 1975, pp. 1-6.
11. Ibid

SECTION III

CHARACTERISTICS OF CONTROLLABLE LOADS

In order to estimate the amount of deferrable load that can be expected from a system-wide application of load control, a knowledge of the load characteristics for both the targeted load for control and the system is necessary. The principle differences between the load pattern at a specific controlled customer and the load pattern at the supply levels involve two variables: (1) the natural diversity existing between individual customers which reflects the differences in time of use for the same appliance or load, and (2) system losses occurring during control periods at the various voltage levels in the distribution system. The nature of the average diversified demand of the target loads during the times of the system peak or other control periods, as well as the voltage level of service on the electric system, are major factors in determining the potential demand deferrable.

Therefore, to assess the potential effect of direct utility load control and to determine the control strategy, it is first necessary to develop the utility's system daily load profiles and the corresponding diversified demand curves of the target appliances for the selected control periods. Ideally, the utility should develop a set of these load curves strictly applicable to its own system, service area, and customers. This chapter provides some "typical" load profiles of appliances which have been controlled, and develops a general relationship for quantifying the maximum controllable load. Control strategy and limitations on the maximum controllable load are analyzed in Section IV.

1. Load Profiles

The amount of the controllable load associated with a particular appliance depends on the number of the appliances connected to the system, its usage pattern when considered as a group, and the maximum kW rating or connected load. The last two factors will determine the "diversified demand" of the appliance at any given point in time. On an aggregate basis, the diversified demand curve reflects the load characteristics of the appliance to be controlled.

Two types of existing residential appliances were considered controllable in Appendix A, the Case Studies of this report are water heaters and central air conditioners. Separate diversified demand curves of these appliances are developed for winter peaking and summer peaking utilities. All load curves were derived from previously published utility test data, and they represent typical data of appliance loads imposed on utility systems. As of 1978, test data on existing residential space heating provided no conclusive evidence of its potential for control. This is discussed at the end of this section.

Water Heaters

The diversified demand curve of water heaters depends on a number of factors which were discussed in the preceding section. A preliminary comparison of Exhibits III-1, III-2, and III-3 illustrate the time varying nature of the load due to these factors. The season and source of supply determine incoming water temperature. Thus more energy for water heaters is normally required in the winter. Washing and dining habits of the service area customers influence the daily load pattern. The design characteristics must also be considered. The older the water heater the lower the wattage of the heating elements. Before 1963 the NEMA standard for water heaters dictated that bottom heating elements could not exceed 20 watts/gallon and that top heating elements could not exceed 30 watts/gallon. Subsequent standards have increased the wattage to 4500 watts per element for a 40 gallon tank. The Case Studies in Appendix A assume a standard 40 gallon capacity water heater with two interlocked 4500W heating elements (only one element is energized at any one time). Exhibit III-1 illustrates some winter daily load profiles for such a water heater. Note that the diversified demand can be as low as 0.03 kW or as high as 1.24 kW depending on the time of the day. The three curves illustrated show a familiar double peaking shape with the peaks occurring at mid-day and in the early evening. Note that one curve, Pioneer Rural Cooperative, shows the peak at noon while the others peak in the evening. Therefore, this exhibit also points out that difference in water heater

EXHIBIT III-1
WATER HEATER DIVERSIFIED DEMANDS
WINTER CURVES
(WEEKDAY)

LEGEND

- DETROIT EDISON, 1969
- WESTERN MASS., 1973
- PIONEER RURAL, 1973 COOP.

demands do exist between utilities. For example, cooperative utilities have historically been less restrictive on heater sizing requirements; and generally the noon meal of rural residents is more often consumed at home than those living in a commercial or industrial environment.

Exhibit III-2 illustrates some summer load profiles for water heaters. Note that for two of the three utilities shown, the peaks occur in the late morning hours. The diversified demand is lower in these curves compared to the winter curves, one principal reason being the higher incoming water temperature. In Exhibit III-2, the summer diversified demand ranges from 0.09 kW to 1.1 kW. Note how dissimilar the three curves are from each other compared to the winter curves.

To further demonstrate the influence of season on water heater loads, Exhibit III-3 shows the diversified demand of water heaters for three hourly periods often being peak hours: 6 to 7 PM, 3 to 4 PM, 11 AM to Noon, during the course of a year. This data is taken from a 1973 Western Massachusetts report. A more detailed description of the test is provided in Appendix B.

One of the most critical characteristics necessary to analyze water heater control is the "payback". Payback consists of the amount of diversified load that is seen by the system when the inhibits are removed from controlled loads. Test data indicates that in the case of water heaters, the restored diversified demand varies rather directly with the length of the the inhibit.⁽¹⁾ That is, the longer the inhibit, the higher the restore demand. Exhibit III-4 taken from Detroit Edison studies provides a graphic illustration. These studies show that if the inhibit existed for as much as four hours, the restored diversified demand was seen to be 4.1 times the diversified demand at the time of inhibit. The curves also show how the payback decays back to normal values rather quickly. These payback curves were utilized in the Case Studies analyzed in Appendix A.

EXHIBIT III-2
WATER HEATER DIVERSIFIED DEMANDS
TYPICAL SUMMER CURVES
(WEEKDAY)

EXHIBIT III-3
THE TIME VARYING NATURE OF DIVERSIFIED DEMAND

EXHIBIT III-4
WATER HEATER RESTORE CURVES

The payback phenomenon requires that the controlled water heaters be divided into separate control groups. This allows the total water heater load to be restored to the system in staggered intervals, avoiding a secondary peak greater than the control target.

Central Air Conditioners

Air conditioners are subjects of load control only in summer peaking utilities. Diversified demand curves of central air conditioners are shown in Exhibits III-5 and III-6. As shown in Exhibit III-5, the diversified demand of air conditioners can range from approximately 1.2 kW to 4.1 kW. Exhibit III-6 illustrates that the peak can occur over a wide range in the afternoon hours depending on temperature. Appendix B provides further data on air conditioner load tests.

Exhibit III-7 illustrates the high degree of correlation that exists between temperature and air conditioner load. It also shows the large proportion that air conditioning represents of the total service load in the summer. This amplifies the point that air conditioning load characteristics are very site specific, emphasizing the need for good load research data before a load control benefit is computed.

Exhibits III-8 and III-9 provide a typical set of results (one residence) from the central air conditioning load control test performed by Arkansas Power and Light in the Little Rock area in 1975. The exhibits are presented to show the effects of load control on the payback period. In Exhibit III-9, the air conditioner was controlled from 1 p.m. to 5 p.m. on August 13, 1975. The unit was switched off twice per hour from 5 to 9 minutes at each interval. Results showed that interrupting 22% of the air conditioners in the test area reduced circuit load by 5 to 10%. Exhibit III-9 also shows that in one residence, the temperature rise was over 4° and payback lasted 5 hours. In Exhibit III-8 the inhibit interval was increased to an interval varying between 9 to 13 minutes (twice per hour). The temperature rise varied from 4° to 9° and the payback period increased to 7 hours.

EXHIBIT III-5
CENTRAL AIR CONDITIONER DIVERSIFIED DEMAND
TYPICAL SUMMER CURVE

SOURCE: GEORGIA POWER COMPANY, AIR CONDITIONING DEMAND CONTROL (ACDC)
TEST, JUNE-AUGUST 1975

EXHIBIT III-6
CENTRAL AIR CONDITIONER PEAK DAY LOAD CURVES
(NORMALIZED)

SOURCE: STAFF REPORT ON LOAD MANAGEMENT STANDARDS,
CALIFORNIA ENERGY COMMISSION, JUNE 1978, P.48

EXHIBIT III-7
AIR CONDITIONER DEMAND VS. TEMPERATURE CURVES

SOURCE: AEIC DATA 1964-1965

EXHIBIT III-8
CENTRAL AIR CONDITIONER
LOAD CONTROL TEST - PAYBACK PERIOD
ARKANSAS POWER & LIGHT
LITTLE ROCK AIR FORCE BASE, SEPT. 2, 1975

SOURCE: LOAD MANAGEMENT BY RADIO CONTROL,
J.S. HOLTZINGER, APRIL 1976 (FIG.23)

EXHIBIT III-9
CENTRAL AIR CONDITIONER
LOAD CONTROL TEST - PAYBACK PERIOD
AUG. 13, 1975
ARKANSAS POWER & LIGHT

SOURCE: LOAD MANAGEMENT BY RADIO CONTROL, J.S. HOLTZINGER
MOTOROLA, APRIL 1976. FIG.20

The Case Studies presented in Appendix A rely heavily on this data for air conditioner payback assumptions.

Space Heating

The load characteristics of space heating are not as easily described as water heating and air conditioning. These latter two are more homogeneous. The various means of residential heating present different load and energy storage qualities, all of which affect load control. A home with electric baseboard heating exhibits a different load curve from one with an electric furnace with forced hot air. The European experience is dramatically different from the U.S. in their approach to home heating and load control. In Europe load control came first, homes and home heating systems were designed with that in mind. In the U.S., the reverse was true. As a result European residences and businesses use the building's mass for heat storage in addition to normal insulating techniques. This allows for extended inhibit times even in cold climates. In the U.S., the average home is not designed for space heating load control. Test data show no consensus as to the effectiveness of load control, but varies with the region. Some examples are offered below.

Exhibit III-10 illustrates the daily load curves of space heaters in four different areas of the country. The profiles show that control would most likely occur for a short interval in the early morning hours and for an extensive period in the early and late evening hours. As pointed out in Section II, however, test data on the effectiveness of controlling typical space heaters existing in the United States has been statistically inconclusive as of 1978. A Preliminary report from one study in California,⁽²⁾ states that space heater cycling would be used no more than 10 days a year. Space heaters were shown to have a lower coincidence factor at the system peak than air conditioners because of oversizing and the winter peak being less temperature sensitive than the summer peak in California. Of course caution should be exercised when extrapolating these results to other areas of the country. The preliminary reports

**EXHIBIT III-10
SPACE HEATER PEAK DAY LOAD CURVE
(NORMALIZED)**

concluded that space heaters could be turned off for longer time intervals than air conditioners without affecting customer comfort.⁽³⁾ This is somewhat contradicted in a study performed at Buckeye Power in 1975 where their report stated that they expected more favorable consumer acceptance of water heater control than control of electric heat.⁽⁴⁾ Another study, by Potomac Edison,⁽⁵⁾ referred to in Section II, demonstrated significant load deferments per customer (up to 10 kW), but general applicability could not be shown since the test was only performed on eight homes. A mass demonstration program was planned for 1978. Despite the small sample size, however, the test did provide interesting "payback" data. It took about 1.5 hours of continuous heating to bring temperatures back to normal after 4 hours of control. Diversified demand was 50% higher than normal during the payback period.

Because of the general paucity of data in this area and their site specific nature, the Case Studies presented in Appendix A did not consider control of space heaters. Further testing, however, might prove these appliances very amenable to load control.

2. Quantification of Potentially Controllable Loads

To estimate the total deferrable demand in kW, first identify each of the appliance types that are to be controlled. For each appliance, the deferrable load will depend on the following factors:

1. Total number of appliances.
2. Customer acceptance rate, which is a measure of the percentage of customers with the appliance who can be expected to participate in the load control program.
3. Load Control Equipment Success Rate.

4. The diversified demand of the appliance load coincident with the time of the system peak (or during other control periods).

The above factors will determine the reduction in load at the customer level. To estimate the load reduction at the supply level, an additional factor should be taken into account, namely, the system loss factor.

To illustrate the procedure of quantifying the effect of controlling water heaters or any other appliance, the value of the factors identified above is assumed as:

a.	Number of customers with water heaters	5,601
b.	Customer acceptance rate	75%
c.	Diversified Demand at the	.8 kW (Winter)
	Control Period	.6 kW (Summer)
d.	Load Control Equipment Success Rate	98%

Based on the above, the potential load reduction at the customer level can be determined by:

$$a \times b \times c \times d$$

Therefore, during the winter period, the potentially controllable load is:

$$5,601 \times .75 \times .8 \text{ kW} \times .98 = 3,293 \text{ kW}$$

To determine the controllable load at the reference level of purchased power delivery point, the loss factor has to be taken into account. The potentially controllable load can be estimated by:

$$a \times b \times c \times d \times \text{Loss Factor}$$

Assuming the capacity loss of the system is 9%, then the loss factor is $1/.91$ or 1.0989 . Therefore, during the winter period, the potentially controllable load at the point of delivery is:

$$5,601 \times .75 \times .8 \text{ kW} \times .98 \times 1.0989 = 3,619 \text{ kW}$$

Substituting the lower summer period diversified demand for that of the winter period, the potentially controllable load becomes:

$$5,601 \times .75 \times .6 \text{ kW} \times .98 \times 1.0989 = 2,714 \text{ kW}$$

SECTION III - FOOTNOTES

1. Load Factor Improvement Through Radio Controlled Diversity, Robert L. Roberts, Pionerr Rural Electric Coop., April 30, 1973, IEEE Conference Paper.
2. Staff Report on Load Management Standards, California Energy Commission, June 5, 1978 (DRAFT) (p. 48-50).
3. Ibid
4. Peak Shaving - A Way to Fight Rising Costs, C. F. Jack, Buckeye Power, Inc., Columbus, Ohio, April 1975. IEEE Conference Paper (p. 3).
5. Demand Controller Shaves Winter Peak, Electrical World, October 1, 1976, p. 93.

SECTION IV

LOAD CONTROL STRATEGY

A. INTRODUCTION

The main objective of developing a peak shaving load control strategy is to limit the system peak demand to a level so that the bulk power costs to the non-generating utility are minimized. After the controllable loads are identified, an evaluation must take place to determine the optional method of control. Methods such as cycling of air conditioners and continuous inhibits of water heaters have been discussed previously in Section II only in general terms. Obviously the control strategy links directly with the benefit/cost analysis. The control strategy determines the amount of deferrable load from the available controllable load. Where system load, power supply arrangements and other conditions require control in both the summer and winter, the effective deferrable load per control switch may be reduced. This, in turn, may have a negative impact on the benefit/cost analysis. For example, assume that control is required in both peak seasons with water heaters and central air conditioners controlled in the summer, and water heaters and central space heaters controlled in the winter. The deferrable load is available per water heater all year round and is determined by the diversified demand. However, to obtain the same annual kW of deferrable demand from the central air conditioner (in the summer) and the central space heater (in the winter) twice as many control switches may be required. Thus the deferrable annual load per control switch is effectively reduced. In some cases, this requirement for additional control switches may neutralize the benefits of load control, even where dual function switches are used to minimize cost. Of course as control switches evolve in sophistication, the price of an extra control relay may become insignificant. These considerations notwithstanding, a "practical control strategy" would incorporate such factors as flexibility, customer acceptance, and hardware capability as discussed in the following paragraphs.

1. Flexibility - The control strategy should be designed to respond to the differing shapes of load profile curves as the system approaches peak demand levels or predetermined control periods. Quick load shed response to inhibit commands and multi-channel capability are therefore required. The multi-control channel capability would further provide for separate commands for each appliance group and for different appliance types. This would avoid the problem of overloading a distribution transformer if the restore commands to all appliances were all on one channel.
2. Customer Acceptance - Minimum customer discomfort can be achieved only if inhibit commands are distributed equally among the customer groups (channels) and appliance off-time is minimized. This is a critical item to consider in air conditioner control where inhibits over 15 minutes an hour may cause significant temperature rises.⁽¹⁾ The same consideration would apply to the cycling of space heating, for which the off-time may be even more critical because of the higher differential between inside/outside temperatures.
3. Hardware Capability - For a load control system to function properly, real time data collection of system demand is necessary. Load control initiation depends on a reliable estimate of when and how quickly the system load is approaching a control target level. This capability may be possible with an additional real-time monitoring system. (This extra cost has been incorporated in the Case Studies included in Appendix A.)

B. DATA REQUIREMENTS

A prerequisite for establishing a load control strategy is the development of a reliable data base. The data base would include: 1) the most current system peak day load profiles for all seasons in which control would be implemented, 2) identification of controllable loads, 3) controlled appliance diversified demand curves for all those periods, and 4) controlled

appliance restore demand curves. Since published information in these areas are based on limited studies and can be a function of a specific area, it may be necessary for the utility to generate its own data. As indicated in Section III, diversified demand curves for water heaters vary according to region and season. The small amount of data collected to date on load restoration demand curves necessitates a cautious application in the control strategy.

C. PROCEDURES

1. Establishing Control Target - With the above mentioned data base established, a control target can be developed. To establish priorities in inhibiting controllable loads, the utility must analyze how the different appliance diversity curves interact. The largest interruptible loads should be considered as a base for load shedding. Irrigation loads exhibit this quality. Air conditioning, because of the sheer size of its load qualifies as a base, even though it is most vulnerable to causing customer inconvenience. Water heaters represent the most convenient deferrable load, because of their energy storage characteristics, but, in many systems they do not represent the majority of controllable loads. In this latter case, water heater load shedding is used to fine tune the control target when larger controllable loads cannot achieve the amount of load drop desired. In some utilities a relatively flat load curve forces long control times and appliance groups may have to cycle with other appliance groups to avoid customer inconvenience. This type of problem lends itself to a linear programming solution. The objective function would consist of minimizing bulk power costs. This would be balanced against imposed restraints of customer acceptance (appliance off-time) and avoidance of secondary peaks (appliance diversity and restore demand information). In the case studies illustrated in the appendix to this report only one utility had more than one type of appliance controlled. In this case air conditioners, representing the largest loads, were controlled first. Water heaters

were later used to provide final load shedding. The result was a rather long control time for air conditioners, but, since no unit was unhibited for more than 15 minutes an hour, there was no assumed customer inconvenience.

The 'tactics' involved in a load control strategy rely on responsiveness. They are developed below for the two principal types of controllable appliances.

If the controllable load has been predetermined to be water heaters only, the straightforward procedure involves multiplying the total number of water heaters by 3 factors: 1) their load diversity at the time of the peaks or control periods, 2) the system loss factor to reflect the load referenced to the bulk power billing point, and 3) the control switch success rate to account for switch failures. The resultant maximum potential controllable load is then subtracted from the system peak demand to obtain the control target related to water heater control.

If the controllable load has been predetermined to be central air conditioners only, a slightly different procedure is necessary. To minimize customer inconvenience, recent tests have shown that only 15 minutes off time is the maximum allowed per central air conditioner in any one hour.⁽²⁾ Therefore, the maximum potential controllable load, as calculated above for water heaters, must be divided by 4 to account for this restriction. (Further testing might alter this restriction for a specific utility.)

For most summer peaking utilities, the maximum diversified demand of central air conditioners is almost 90% of the average air conditioner's connected load (implying that the air conditioning compressors are running almost continuously on the hottest days). Consequently, little diversity of air conditioner demand normally occurs on the summer peak. Maximum diversified demand, during control, is reached

approximately after two inhibit cycles and at an earlier time than would occur without control. Maximum diversified demand after a control period could actually be higher than normal demand because of restore demand effects. In any event it is, in many cases, very close to the connected load of all air conditioning at that time.

When central air conditioners are controlled during periods when temperature is below maximum, where insulation standards are high or where thermostat settings may be relatively high, the increased diversity of air conditioning demands will substantially affect the control strategy. Tests conducted by both a midwestern⁽⁷⁾ and western utility,⁽⁸⁾ for example, show that with a natural diversity of 50% of the air conditioners being on at any one time, very little load was being shed as a result of cycled inhibits. In other words if the inhibit cycle causes a unit to be "off" 25% of the time and "on" 75% of the time, the average demand of the air conditioner will not be affected. The unit will still be allowed to run 50% of the time to satisfy the cooling requirements of the home. The net effect is to shift the "off" period of the unit.

2. The Inhibit and Restore Sequence - With the control target for each load established, the strategy next involves the inhibiting of loads as this level is approached so that it is never exceeded. The controllable load is then divided into a number of groups which is determined by the number of control channels available. As noted previously for air conditioners, the number must be such that approximately 25% can be controlled at any one time. The inhibit and restore sequence necessary to keep the system load below the control target is discussed below for water heaters and air conditioners.

- a. Water Heaters⁽³⁾ - The system monitor observes the load increasing on a real time basis. At frequent intervals, this value is compared with the control target and the load profile that

determined this control target. Based on this load profile's slope, the monitor initiates inhibit commands to a sufficient number of groups to stay below the control target until the time of the next sample. Group demand is a function of water heater diversity at the time of inhibit. It also must be adjusted by the loss factor and switch success rate previously mentioned. Because of the time varying nature of diversified demands, continuous monitoring during the initial inhibit sequence will probably be required. Generally, the initial inhibit sequence, i.e., the removal of all water heater load from the system, is completed within an hour or less.

Total off time will depend on the system load profile. The width and slope of the system peak will determine off time and the initiation of restore. The restore sequence begins as soon as the system load profile decreases sufficiently below the control target.⁽⁴⁾ In other words, the difference between the control target value and the actual demand must be at least as great as the first group's restore value. The first group inhibited must be the first group restored to satisfy the minimum off-time objective. The order of restore would then follow the order of inhibit. Restore values are calculated as follows: the diversity of each group at the time of inhibit is multiplied by the loss factor, switch success rate, and restore multiplier. The restore multiplier is the ratio of returning load to initial load. These ratios are statistical averages derived from several tests. This data also indicates the manner in which the restore values decay over time to normal values, i.e., the payback period. (See Exhibit III-4). To observe the effects of the first group's restored demand, the initial restore value is added to the load curve with all water heaters off at the time of the restore command. The payback curve is drawn from this point, establishing a revised system load profile. When this revised load profile drops sufficiently

below the control target, the next group may be restored. Then in the same manner as before, this payback curve is added to the first payback curve to establish another load profile. This sequence continues until all groups are restored. Note that depending on the slope of the load profile, it may be possible to restore more than one group at a time. Conversely, some time intervals may have to be skipped to allow for adequate load decay. (For simulations of heaters, refer to the exhibits in the Case Studies, Appendix A.)

- b. Central Air Conditioners - For central air conditioners, the inhibit and restore sequences consist of group cycling. Groups can be inhibited only for short intervals (previous tests have used 7-1/2 minutes, no more than twice an hour)⁽⁵⁾ to minimize customer discomfort. The inhibit sequence begins when the system monitor projects a load demand above the predetermined control target, as previously explained for water heaters.

Group demand is determined from applicable diversity curves. Once the inhibit sequence is initiated, all groups are cycled in 7-1/2 minute intervals. It may become necessary to cycle two groups at a time as the system load increases rapidly. (Restricted by the fact that no group may have more than two 7-1/2 inhibit periods in any one hour.) After two inhibit cycles, it is assumed that each group requires the maximum diversified demand. Therefore, after the second cycle, the resultant load profile is established by adding 3/4 of the maximum diversified demand of the total central air conditioning load (times loss factor and switch success rate) to the load curve with central air conditioners removed. As the revised load profile drops below the control target, central air conditioning load is restored by discontinuing the cycling sequence as soon as possible while still not exceeding the control target. The restore information on central air

conditioners shows that payback (the time necessary to satisfy the original thermostat setting) can be anywhere from 3 to 7 hours.⁽⁶⁾ This range of payback emphasizes the need for system unique data collection in this area for each utility. The maximum diversified demand extends through the length of the restore period. This means that the load curve after all central air conditioner groups have been restored is determined by adding the maximum diversified demand of the total central air conditioners to the base load curve with central air conditioning removed. This resultant load profile extends through the duration of the restore period.

D. RESULTS OF CONTROL STRATEGY APPLICATIONS

The above procedures were utilized in establishing a control strategy for each of the four case studies included in this report. In each case, a control target was successfully maintained with an equitable distribution of off-time between appliance groups. A brief summary of the results is given below. Detailed results of load control strategy may be found in the Case Studies (Appendix A) of this report.

Case 1: Winter Peaking Urban Utility - 5,601 water heaters were controlled for this northeast utility. Divided into ten groups, the water heaters were given inhibit commands over a period of 30 minutes from 4:15 p.m. to 4:45 p.m.; all water heater groups were held off until 6:00 p.m. the restore sequence took place over a two hour and 45 minute period from 6:00 p.m. to 8:45 p.m. Longest group off time was four hours. The peak demand was reduced by 4825 kW or 8%.

Case 2: Winter Peaking Rural Utility - 3986 water heaters were controlled for this midwest utility. Divided into ten groups the water heaters were given inhibit commands over a one hour period from 4:45 p.m. to 5:45 p.m.; all water heater groups were held off

until 9:00 p.m.; the restore sequence took place over a 4-1/2 hour period from 9:00 p.m. to 1:30 a.m. Longest group off time was seven hours and 45 minutes. The peak demand was reduced by 3340 kW or 13.6%.

- Case 3: Summer Peaking Urban Utility - 4286 central air conditioners were controlled for this southwest utility. Divided into eight groups, the central air conditioners were cycled for a 4-1/2 hour period from 3:00 p.m. to 7:30 p.m.; the restore time was assumed to be seven hours. Each group was given the inhibit command eight times. The peak demand was reduced by 4616 kW or 3.2%.
- Case 4: Summer Peaking Rural Utility - 3773 water heaters and 3706 central air conditioners were controlled for this southwest utility. The load was divided into ten water heater groups and eight central air conditioner groups. Water heaters were given inhibit command over a period of three hours from 3:45 p.m. to 6:45 p.m.; all water heater groups were held off until 11:30 p.m.; restore sequence took one hour and 15 minutes from 11:30 p.m. to 12:45 a.m. Longest group off time was eight hours. Central air conditioners were cycled for ten hours, from 2:00 p.m. to 12:00 a.m., the restore time was assumed to be three and one-half hours. Each group was inhibited 18 times. The peak demand was lowered by a total 6429 kW or 11.4%.

Significant Findings

The influence of the load profile on appliance off times becomes apparent. For example in Case 2, the relatively broader peak and high proportion of controllable load (13.6%) produces off times up to 7.75 hours. In contrast, Case 1 has a sharper peak and smaller controllable load (8%). The maximum off time in this area as a result is only 4 hours.

In comparing Cases 3 and 4, the effect of payback periods becomes apparent. In Case 3 where a seven hour payback was assumed, the kWh gain appears to be larger than the kWh loss. In Case 4, where a three and one-half hour payback was assumed, kWh gain is roughly equivalent to kWh loss. Finally, in Case 4 where two different appliances, water heaters and central air conditioners were being controlled, water heater off time was increased. This can be attributed to the high percent of load reduction and the load profile shape as explained in Case 2 above.

E. SYSTEM CONTROL VS. SUBSTATION CONTROL

Some manufacturers of load control equipment have taken the position that deferring system peak demands through load control will result in reduced distribution plant investment and the associated costs. This assumption implies that the controlled demands at the time of the system peak are directly related to reduced peak demands on the distribution network. In other words, substation transformer and secondary transformer capacity can be reduced or system reinforcement postponed as a result of the control scheme designed to reduce system peak conditions.

This assumption would be credible if substation maximum demands and localized peak conditions throughout the distribution network occurred coincidentally with the system peak. In an attempt to assess the validity of this assumption, the time of the system peak and the times of the various substation peaks were compared for a large cooperative system (see Exhibit IV-1). The comparison shows that less than 5% of the distribution substations peaked at the same hour as the system peak and only 14% peaked on the same day as the system peak. Based on these observations, approximately 5% of the substations reviewed would have reduced peak demand to some extent by controlling only at the time of the system peak, and 14% of the substations would have altered peak day load profiles as a result of a control scheme using system peak criteria.

Another factor to consider is the frequency with which the substation's demand approaches its peak. Diversity of peak loads decreases as distance from the supply point increases, consequently, the frequency of approaching a load peak is higher at the final distribution level than it is at the system level. This implies that more control periods would be necessary at the distribution level. In other words, to effectively limit the peak in the distribution network and create savings by deferral of investment, a substantial number of additional control periods would have to be imposed above those required for system peak control. In a few cases, individual substation peaks may, in fact, occur during a restore period under a system peak control scheme, increasing the problem of overloading the substation, rather than deferring distribution investment. Remote metering equipment would be required at each substation in order to detect the upcoming peaks. Ultimately, additional addressing capability would be imposed on the control system so individual feeders would be controlled independent of each other. The preceding analysis involving the relationship between the load restoration demand and numbers of channels required would also be greatly increased in complexity.

Under these conditions the capability of the initially conceived peak load control system would be exceeded. The technical feasibility of such a sophisticated control scheme has not yet been demonstrated. Therefore, any benefits attributed to reduce demands on the distribution network must be considered premature until an adequate control strategy can be achieved and cost of this additional capability can be included in the cost-benefit analysis.

EXHIBIT IV-1

SUBSTATION AND SYSTEM PEAKS:
COMPARISON OF PEAK OCCURENCES

SUBSTATION	PEAKING IN THE SAME MONTH AS THE SYSTEM	PEAKING ON THE SAME DAY AS THE SYSTEM	PEAKING AT THE SAME TIME AS THE SYSTEM
1	X	X	
2	X		
3	X	X	X
4	X		
5	X	X	
6	X	X	
7	X	X	X
8	X	X	
Total Substations Reviewed - 42	19%	14%	4.7%

Source: Western Farmers Electric Cooperative, Hourly Substation
 Load Data, July 1978

This Exhibit summarizes a representative sample of the total 230 substations supplied from a common bulk power supplier. Hourly demand data was reviewed for each of the sample substations in order to determine the relationship between the overall system peak and individual substation peaks. It can be seen that the majority of substation peak demands would not be reduced by a control strategy designed to limit the overall system peak. Therefore, there would likely be little capacity savings in the distribution system if such a control strategy were employed.

CHAPTER IV FOOTNOTES

- (1) Peak Load Control Study - Summer of 1975, Arkansas Power and Light Company. p. 10.
- (2) Ibid.
- (3) Charlie F. Jack (Buckeye Power), "Peak Sharing - A Way to Fight Rising Costs". 1975 Rural Electric Power Conference. Omaha, Nebraska. April 27-29, 1975. (C75 310-8-IA) p. 4.
- (4) The "load profile" now consists of a base load curve with water heaters removed.
- (5) Peak Load Control Study - Summer of 1975, Arkansas Power and Light Company. p. 10.
- (6) Ibid Appendix I.
- (7) Central Illinois Light Company Load Management Studies - Report to Illinois Commerce Commission, December 21, 1978.
- (8) E.T.K. Law, Pacific Gas & Electric Company's residential central air conditioning load control experiment. EPRI Workshop in "new modes of residential HVAC; Economic incentives and barriers" January 14-17, 1979 Tampa, Fla.

SECTION V

A SIMULATION TO ANALYZE THE RESTORE EFFECTS OF DIRECT LOAD CONTROL ON A DISTRIBUTION NETWORK

A. MODEL

To study the effects of changing the demands on a distribution network, computer models¹ of two actual utility systems' distribution networks were constructed. Parameters tested were transformer loading, line loading, and voltage drop. The models incorporated the size, spacing, impedance, and length of each conductor at each section (the interim between the nodes). Loads were inputted at each 'node', a point along the line where a branch or load appears, by knowing the customer types at each node and the demand per customer as derived from a customer demand analysis of the specific utility. The analysis determined a diversified demand by rate class at the time of system peak. Billing print-outs identified the numbers and rate class of each customer at each distribution transformer. The program also included the name plate capacity of each distribution transformer and power factors based on these loads. Two different types of utilities were tested: a summer peaking rural system and a winter peaking rural system. The model tested these utilities under two loading conditions: a normal coincident system peak condition, and a "worst case" restore condition immediately after a control period.

B. ASSUMPTIONS

The model is limited in general application by the following assumptions:

1. The model assumes that all restore values occur at each node simultaneously and that no cycling occurred. (Note that this assumption was relaxed in the control strategy simulations, including both concurrent and cycled inhibits). The distribution model reflects a more conservative approach as a result.

2. Only residential loads are considered.
3. For the base case, i.e. normal system peaking condition, the model utilized diversified demands for each customer rate class that were previously developed in the above mentioned demand program. It should be emphasized that these demands were unique to the two utilities involved. The diversified demands incorporated were:

Winter Peaking Utility

<u>Class</u>	<u>System Peak Case</u>
Normal Residential	1.5 kW
Residential W/Water Heating	2.4 kW
All Electric	8.1 kW

Summer Peaking Utility

<u>Class</u>	<u>System Peak Case</u>
Normal Residential	1.7 kW
Residential W/Water Heating	2.8 kW
All Electric	4.4 kW

4. For the restore case, the distribution model utilized diversified demands for each customer rate class developed from Detroit Edison restore tests. The appliance restore curve was added to typical residential load curves without water heating to obtain resultant load profiles. Note that this analysis was conducted for water heaters only. The details of the restore demand values obtained for the residential with water heater and residential all-electric classes are discussed in part C. (The regular residential class was not affected by restore demand.)

Restore demands utilized were as follows:

WINTER PEAKING RURAL

<u>Class</u>	<u>kW</u>
Normal Residential	1.5 kW
Residential W/WH	5.8
All-Electric	9.9

SUMMER PEAKING RURAL

<u>Class</u>	<u>kW</u>
Normal Residential	1.7
Residential W/WH	7.3
All- Electric	7.0

WINTER CONDITION OF SUMMER PEAKING RURAL

<u>Class</u>	<u>kW</u>
Normal Residential	1.7
Residential W/WH	5.8
All-Electric	9.9

5. The program calculated voltage drop by standard vectorial multiplication of the impedance of the line and the kVA of the load. A 'branch' met the acceptance criteria for voltage drop if the drop was 5% or less of normal line to ground voltage. (A 'branch' is a series of contiguous nodes between the load and substation.)

6. The program calculated line loading by comparing load ampacities with standard allowable cable ampacity tables. A section met the acceptance criteria for line loading if the ampacity on the conductor was less than 100% allowable.
7. The program calculated capacity factor by dividing kVA of the load by transformer name plate capacity. A node met the acceptance criteria if the transformer loading was less than 150%.

C. RESTORE DEMAND DERIVATIONS

1. Winter Peaking Rural

1. Residential W/Water Heating (Reference: Exhibit V-1)

A 'base' load curve of a customer's diversified demand without water heating was first constructed by drawing a typical midwestern utility customer's regular residential winter day load profile. (This is labeled "without WH" in Exhibit V-1.) The curve was adjusted for water heater demand by adding a typical water heater diversified demand curve (Exhibit 1A in the Appendix). The resultant curve, labeled "with WH", represents the average residential W/WH daily load profile. Restore time was determined from the average of all the restore commands derived in Case Study #1, a winter peaking utility. (Note that in this instance, the restore command happens to coincide with the individual's peak). The average off-time and time of inhibit were determined from the case study in a similar manner. The diversified demand at the time of restore was then determined from the Detroit Edison restore curves.

As Exhibit V-1 shows the normal peak diversified demand total customer (without water heating) was 1.3 kW. At the selected time of restore (7 pm), the water heater demand was determined by

EXHIBIT V-1
DIVERSIFIED DEMAND CURVE
RESIDENTIAL WITH WATER HEATING
(WINTER PEAKING RURAL UTILITY)

multiplying 0.8 kW (water heater peak diversified demand) times 3.81 (Detroit Edison restore multiplier) or 3.05 kW. The resultant demand was computed as 4.35 kW at the time of restore. A safety margin of (1/3 of restore demand) was added to insure a conservative estimate. The total demand at time of restore used in the model was determined to be 5.8 kW.

b. Residential All-Electric (Reference: Exhibit V-2)

In this instance, the midwestern utility's residential all-electric curve was drawn first and the diversified water heater demand removed, utilizing the same water heater diversified demand data (Exhibit 1A, Appendix). Average inhibit, off-time and restore commands times were then selected. Restore demand multiples were derived again from Detroit Edison test data.

The 'normal' peak demand, as Exhibit V-2 illustrates, was 5.4 kW at time of restore. The amount of water heater restore demand was 3.05 kW. To ensure conservation estimate, a safety margin was again added to this for a resultant 9.9 kW demand at time of restore.

2. Summer Peaking Rural

a. Residential With Water Heating (Reference: Exhibit V-3)

This procedure was identical to the one followed in the first case except that a summer peaking demand curve was used. After the two demand curves, (with and without WH) were established, the restore demand for water heaters was determined to be .6 kW (maximum diversified demand-summer) x 4.9 (restore multiplier - Detroit Edison) or 2.95 kW. This was added to the 2.25 kW demand existing at that time without water heaters resulting in a demand at restore of 5.2 kW. A sufficient safety margin was also added to produce the final restore demand of 7.3 kW as shown in Exhibit V-3.

EXHIBIT V-2
DIVERSIFIED DEMAND CURVE
RESIDENTIAL ALL ELECTRIC
(WINTER PEAKING RURAL UTILITY)

EXHIBIT V-3
DIVERSIFIED DEMAND CURVE
RESIDENTIAL WITH WATER HEATING
(SUMMER PEAKING RURAL UTILITY)

b. Residential - All Electric (Reference: Exhibit V-4)

Following the procedure outlined in the previous all electric case, but utilizing both a summer peaking demand curve and a summer water heater diversified demand curve (Exhibit 4B - Appendix), the normal peak demand at time of restore was computed as 2.5 kW (see Exhibit V-4). A water heater restore demand of 2.95 as well as a safety margin for conservation were added to produce a total demand of 7.0 kW at the time of restore.

c. Winter Condition of Summer Peaking

The restore demand values for this condition were determined in exactly the same manner as the winter peaking rural utility case.

D. RESULTS

1. Summer Peaking Rural System

This system was analyzed to observe the effect of controlling central air conditioners and water heaters in the summer and only water heaters in the winter. Control in the winter was considered to account for a ratchet effect. That is, the reduction in the summer peak would be significant enough to require some control of the winter peak also, to prevent the winter peak from establishing a new billing demand level through the ratchet. As mentioned previously, three parameters were measured: total transformer loading at each node, voltage drop changes in each line section, and line loading changes. Exhibits V-5 and V-6 summarize the results. Exhibit V-5 lists the worst case section 'performer' in each feeder to isolate problem areas. Note that both the summer and winter tests yielded favorable results as nearly all sections passed the acceptance criteria by a significant margin. Section 138 of Feeder 6 in the winter test had the only voltage drop greater than

EXHIBIT V-4
DIVERSIFIED DEMAND CURVE
RESIDENTIAL ALL ELECTRIC
(SUMMER PEAKING RURAL UTILITY)

EXHIBIT V-5

SUMMER PEAKING RURAL SYSTEM

Summary of Restore Effects

WORST CASE SECTION IN EACH FEEDER

SUB	FEEDER	MAX. V DROP				LINE LOADING			
		Section	Norm.	Restore	% Increase	Section	Norm.	Restore	% Increase
A. SUMMER CONDITION									
Blanchard	1	121	.03%	.04%	33	117	.5%	.7%	40
	3	82/88	2.2	3.1	41	46	14.8	20.8	40
	4	14	1.3	2.0	54	13	14.0	22.2	58
Sunshine	3	192	.4	.7	75	190	7.0	11.4	63
	5	18	1.1	1.6	45	21	14.3	19.1	33
	6	138	3.3	5.0	51	124	19.3	28.7	47
	7	967	2.5	3.8	52	262	7.8	11.5	47
	8	254	2.4	3.5	46	209	13.7	19.5	42
B. WINTER CONDITION									
Blanchard	1	121	N/A	.05	N/A	117	N/A	.8	N/A
	3	88	N/A	3.6	N/A	46	N/A	24.7	N/A
	4	14	N/A	2.7	N/A	13	N/A	30.3	N/A
Sunshine	3	192	N/A	.7	N/A	190	N/A	11.6	N/A
	5	18	N/A	1.9	N/A	21	N/A	22.8	N/A
	6	138	N/A	6.1	N/A	124	N/A	36.0	N/A
	7	957	N/A	4.4	N/A	262	N/A	13.6	N/A
	8	254	N/A	3.9	N/A	209	N/A	22.7	N/A

NOTE: Because of the proximity of summer and winter peaks in this case, the winter condition is also analyzed to avoid ratchet - induced penalties.

EXHIBIT V-6SUMMER PEAKING RURAL SYSTEMSummary of Restore Effects

SUBSTATION	FEEDER	#NODES	NO. OF NODES WITH 50% OR MORE OF TRANSFORMER CAPACITY USED NORMAL/RESTORE	NO. OF SECTIONS WITH 15% OR MORE LINE AMPACITY USED NORMAL/RESTORE	NO. OF BRANCHES WITH 5% OR MORE VOLT DROP NORMAL REST.
Blanchard	1	4	0/0	0/0	0/0
	3	20	2/3	0/2	0/0
	4	17	4/4 (A)	0/4	0/0
Sunshine	3	20	2/2	0/0	0/0
	5	30	5/7 (B)	0/4	0/0
	6	28	5/10	1/1	0/1
	7	32	5/11 (C)	0/0	0/0
	8	74	7/11 (D)	0/3	0/0
Totals		225	30/48	1/14	0/1

Winter Results of Summer Peaking System (Restore Values Only)

Blanchard	1	4	0	0	0
	3	20	4	3	0
	4	17	-	5	0
Sunshine	3	20	4 (1)	0	0
	5	30	8 (2)	3	0
	6	28	12 (3)	3	1
	7	32	15 (4)	0	0
	8	74	15	6	0

NOTES: (1) 3 Nodes over 150% (A) 3 Nodes over 150% Norm, 3 Nodes Restore
 (2) 1 " " " (B) 2 " " " " , 3 " "
 (3) 2 " " " (C) 0 " " " " , 2 " "
 (4) 5 " " " (D) 3 " " " " , 3 " "

No line was loaded greater than 36%

5%. Exhibit V-6 presents a comparison between normal peak and restore load effects with all nodes considered. The comparison is more sensitive in this exhibit since transformer loadings above 50% at each node, line loadings above 15%, and voltage drops over 5% are registered. Totals are given for each parameter. Note, for example, that of the 225 nodes, 30 nodes had over 50% transformer loading under normal peak conditions. This number increased to 48 nodes under restore conditions. An inspection of the notes at the lower portion of Exhibit V-6 reveals that of the 48 nodes just mentioned, 11 had transformer loadings of 150% in restore. Furthermore, of these 11, 8 were overloaded initially before the load control. In conclusion, this system was quite 'soft' and could have absorbed a much larger load with no detriment. This can probably be attributed to the use of standardized system components and conductors. The design is therefore conservative and not tailored to actual network loads.

2. Winter Peaking Rural System

This utility was analyzed to observe the effects on the distribution lines of controlling water heaters in the winter. The changes in the three parameters stated previously were compared between the two conditions of normal system peak demand and restored demand. Exhibits V-7 and V-8 summarize the results. Exhibit V-7 lists the "worst case" individual section in each feeder for both voltage drop and line loading under normal and restore conditions. Note that of the 18 sections failing the voltage drop acceptance criteria under restore conditions, 11 failed under normal system peak conditions. When these 11 are under restore conditions the voltage drop is severe enough to prevent most motors from starting. In most cases the cause for the voltage drop was undersized cable. Exhibit V-7 illustrates that line loading is not a critical parameter in load restoration as only one section out of 1,201 exhibited a loading greater than 100%. To gain more sensitivity Exhibit V-6

EXHIBIT V-7

WINTER PEAKING RURAL SYSTEM

Summary of Restore Effects

WORST CASE SECTION IN EACH FEEDER

SUB	FEEDER	MAX. V DROP				LINE LOADING			
		Section	Norm.	Restore	% Increase	Section	Norm.	Restore	% Increase
1	1	408	2.9	3.2	63	404	22.5	34.4	53
	2	326	4.3	6.5	51	311	17.3	25.5	47
	3	361/360	.4	.7	75	355	3.9	6.0	54
	4	388	7.0	13.1	87	373	22	43.3	97
2	1	280/281	6.5	11.4	75	387	22.3	37.9	70
	2	207	3.4	5.7	67	191/163	14.4	23.7	64
	3	140	3.0	5.1	70	133	14.6	24.6	68
3	1	44	10.0	17.0	70	1	25.8	45.2	75
	2	80	.8	1.3	62	64	5.2	8.0	54
	3	91	2.8	5.0	78	92	10.2	19.0	86
	4	63	.8	1.3	62	61	6.2	9.0	45
4	1	529	2.0	3.6	80	512	10.6	19.2	81
	2	493	2.0	3.4	70	459	8.2	13.8	68
	3	544	1.0	1.9	90	1,267	9.5	16.2	70
5	1	1,063	2.9	5.0	72	1,027	11.0	19.1	73
	2	1,090	6.8	9.3	37	974	39.1	56.2	43
	3	1,121	3.0	5.0	67	1,065	14.3	22.5	57
6	1	972	2.5	4.6	84	1,281	9.7	18.7	93
	3	939	.6	0.9	50	938	3.3	5.0	51
7	1	1,190	18.0	31.5	75	1,204	67.9	*125.1	86
	2	1,140	1.3	1.9	46	1,134	23.4	32.8	40
	3	1,170	5.0	8.6	72	1,159	17.0	29.4	73
	4	1,149	.6	1.0	67	1,289	20.0	32.3	61
8	2	867	7.4	10.5	42	867	33.7	48.3	43
10	1	604	12.7	20.8	64	547	49.9	85.8	72
	2	642	5.1	8.8	72	618	25.6	43.5	70
	3	657	12.0	17.3	44	662	52.0	75.2	44
	4	617	2.7	5.2	92	611	19.1	36.5	91
11	1	617	0	0	0	611	0	0	0
	2	852	29.5	83.5	240	891	27.5	48.1	75
	4	931	3.0	4.4	46	919	18.4	24.2	31

Voltage Acceptance Criteria Not Met

* Line Loading Criteria Not Met

EXHIBIT V-8WINTER PEAKING RURAL SYSTEMSummary of Restore Effects

SUBSTATION	FEEDER	#NODES	NO. OF NODES WITH 50% OR MORE TRANSFORMER CAPACITY USED NORM/RESTORE	NO. OF SECTIONS WITH 15% OR MORE LINE CAPACITY USED NORM/RESTORE	NO. OF BRANCHES WITH 15% OR MORE VOLT DROP NORM/RESTORE
1	2	43	12/27	1/7	0/1
	3	8	4/4	0/0	0/5
	4	70	13/44	6/9	3/13
2	1	82	4/15	4/15	1/13
	2	49	0/3	0/13	0/1
	3	46	0/4	0/4	0/2
	4	84	3/14	3/14	7/9
3	1	49	13/31	9/11	4/5
	3	65	11/30	0/4	0/1
	4	21	1/19	0/0	0/0
4	1	27	5/36	0/1	0/0
	2	42	8/6	0/0	0/0
5	1	44	10/27	0/4	0/0
	2	65	22/46	9/14	11/11
	3	30	9/19	0/5	0/0
6	1	33	6/24	0/3	0/0
	3	25	2/5	0/0	0/0
7	1	57	15/40	12/18	11/7
	2	21	4/11	3/5	0/0
	3	37	5/27	1/7	2/4
	4	9	2/6	1/1	0/0
8	2	37	9/22	13/17	2/3
10	1	66	15/51	10/16	9/10
	2	26	6/21	3/7	1/3
	3	83	16/53	12/21	3/8
11	1	57	6/32	6/8	0/5
	4	25	4/15	22/7	0/0
Totals		1,201	252/742	94/193	55/101

illustrates the number of nodes with transformers loaded above 50% and with lines above 15%. In addition, the last column shows the number of branches with voltage drops greater than 5%. Of the 1,201 nodes, 252 had a capacity factor greater than 50% under normal system peak conditions. This number increased to 742 for the restore conditions. Of this later figure, 32 were over 150% capacity. Note, however, that this was the capacity of the node. A node can be made up of more than one transformer. In the line loading analysis, 94 of the 1,201 sections had over 15% loading under normal peak conditions. This number more than doubled to 193 with restore loading. Only 1 line, however, violated the 100% criteria. Finally, 55 out of 230 branches had over 5% voltage drops under normal peak conditions, jumping to 101 under restore. Exhibit V-5 illustrates the worst cases.

In conclusion, the results for the winter peaking utility show that even under the worst restore condition less than 32 out of 1,200 nodes had possible transformer loading problems, practically no line had any overcurrents, and 46 (i.e. 101 restore - 55 normal) branches out of 230 had voltage drop problems. Therefore, for the analysis conducted here, restoration under the worst conditions of undiversified load can be withstood by the distribution network without major consequences. The winter peaking utility case, however, does point out the need to cycle the restoration of controlled appliances to insure reliable service, and a need to evaluate small transformers (below 10 KVA) serving controlled customers. The evaluation may result in a changeout to a larger transformer or larger lines in a few isolated cases.

The utility distribution networks selected for analysis in this study are assumed to exhibit loading conditions at system peak which are fairly representative of the distribution network for non generating utilities. Overall distribution design characteristics are also considered to be fairly representative of the industry. However, caution must be exercised

in formulating general conclusions for all non generating utilities or when extrapolating the results to specific cases. Older systems, those in need of system reinforcement, or specific areas in the network operating closer to the design criteria should be analyzed carefully to anticipate any problems which may result from load control. Although the impact of control and restoration on the generation and transmission supplier is outside the scope of this report, their stability requirements support the philosophy of cycling restored load.

FOOTNOTE:

1. "Computerized Distribution Planning", Electrical World, April 15, 1974.

SECTION VI

COMMUNICATION AND CONTROL SYSTEM DESCRIPTION AND COST CONSIDERATION

Selecting Candidate Systems

Once an analysis of the customers, loads and physical systems of the distribution utility has been obtained, a review of the available generic types of systems is necessary to select the suitable equipment alternatives. This phase of the selection process will indicate which systems will accomplish the required functions to meet the preset objectives, which systems may offer additional secondary functions, and how to construct the related cost of the systems selected.

The communication and control systems are described as current design technology now exists. Existing systems specifications will undoubtedly be modified and improved over time and new systems are on the drawing board which will increase the spectrum of communication paths and equipment choices presently available for end use load control, systems functions and remote meter reading. In any event, the following section reviews only those generic types of utility control systems existing or expected to exist within 1 to 3 years. These include radio, low frequency power line carrier, high frequency power line carrier, hybrid-radio/power line carrier, telephonic and direct wire systems.

In addition to the basic characteristics of each type, this section covers the direct vendor cost components and those components of indirect cost involved in the installation and initial setup of the equipment.

The Characteristics of Communication and Control Systems

The communication and control systems presently being marketed have inherent design differences that need to be recognized. Different communication paths are utilized with obvious characteristic differences in component equipment.

The purpose of this portion of the task is to expose the potential strengths or weakness of each generic control system with regard to the parameters inherent in any specific distribution system. For each generic type discussed, the following broad categories are addressed.

- a. Origin of system.
- b. Simplified system description.
- c. Engineering application considerations and the influence of the power system network.
- d. Installation considerations for devices located at the customers location.
- e. Major cost factors.

To further illustrate the application of each generic system to a typical distribution network, an idealized layout typical of the major apparatus and interconnections likely to be found in any average utility is shown in Exhibit VI-1. This network layout is subsequently modified for each communication system to illustrate the portions of the power network which are utilized for the communication channel, the point of major interface between the control system and the power system and the location of the major components.

VHF Radio

Direct radio control of remote devices is a well established technique. Its application for the control of end-use customer loads involves little more than an adaption of existing hardware. Large-scale integrated circuit design has resulted in smaller, less costly and more reliable units capable of close frequency tolerances and suitable for bulk production. The radio system

GENERATION AND
TRANSMISSION

BULK SUPPLY
POINT

DISTRIBUTION
LINE

L. V. DISTRIBUTION
TRANSFORMER

SERVICE
CABLE

CUSTOMER'S
WIRING

CENTRAL
CONTROL

TYPICAL DISTRIBUTION SYSTEM
MAKEUP

EXHIBIT VI-1

components are now available in quantity production. A number of utilities in the United States installed extensive radio systems for load control with excellent results.

Radio transmitters operate on Federal Communication Commission administered frequency bands with frequencies being allocated for load control systems in specific locations. The possibility of a joint use of load control signals with a utility's existing VHF voice communication is permitted if required.

Simple audio-tone frequency modulation can be used to activate the single-tone decoder at the end-use location. Block addressing is then possible by utilizing selected tones for individual commands to each group of receivers preset for a particular tone. As an alternative, coded tone signals may be used where multiple commands are required at each receiver location.

The control of end-use loads is initiated by transmitting "off" commands that activate the remote radio switch and disconnect the equipment to be controlled. The receiver will restore the disconnected appliance after a preset delay if an additional transmitted signal is not received. Prolonged "off" cycles can be obtained by retransmitting the appropriate tone before the expiration of the time delay.

Transmission within the frequency band allocated is generally immune from normal day and night variations in the signal path. Some compromise in the channel reliability can be expected at infrequent intervals by freak long distance reception of a remote transmitter due to sporadic ionization layers in the upper atmosphere. The probability of false operation due to the precise matching of the correct modulated tone signal is considered to be minimal. The use of frequency modulation and the design of the detector makes it possible to obtain a receiver characteristic which is largely immune from noise interference, either atmospheric or man-made.

At this time, radio control systems are limited to one-way communication for the purpose of load control. Remote receiver/transmitters are being developed that may permit bi-directional radio system applications in the future.

Significant parameters in the use of radio systems are:

1. As a general rule, the land topography will influence the effective range of any given transmitter. The physical dimensions of the utility's service area will govern the number of transmitters required. Locations involving flat or rolling terrain will obtain the best coverage, while mountainous areas will be subject to valley locations which will be difficult to cover due to shielding from the radio signal.

Applications involving urban areas will be subject to man-made radio frequency noise such as that generated by electrical appliances and motor vehicle ignition. It will be desirable to reduce the transmitter coverage area in these locations to compensate for the increased noise levels and the loss of signal strength due to building screening.

2. Application of radio control to a given area is relatively simple. For most utilities already using VHF base station voice communication equipment, the major portion of the engineering work required is completed. The coverage experienced by the present voice communication system can be directly correlated with the expected performance of the load control system in a majority of locations. Where improvements are required in fringe areas, systems utilizing multiple transmitters can be arranged for a degree of "overlap" in the service area of two transmitters to cover these points. Omni-directional antennas are generally employed, however, coverage of specific portions of the system may be improved (and coverage of unwanted areas prevented) by the use of modified antenna designs.

3. In those cases requiring multiple transmitters for coverage of the distribution system area, the transmitters should be arranged for sequential keying to prevent mutual interference. Communication between the central control point and the transmitters may be by leased telephone lines, central control radio link or microwave system.
4. The radio system is completely unrelated to the distribution system, and the mode of operation of the electrical system has no effect on the communication path. Communication is maintained regardless of network switching, abnormal operating routines or arrangement of bulk supply points. Load growth or extensions to the network will not require changes to the existing installed system for control provided such extensions are within the service area of the transmitter. Extensions outside of the transmitter's service area may require either an additional transmitter or the relocation of an existing unit.
5. Location of the receiver on the customer's premises is relatively flexible and simple. Generally, receivers may be located at any convenient position, such as the incoming electric panel or at the end-use equipment location. However, some restrictions may apply in fringe areas where the signal strength is marginal and with certain types of building construction causing heavy screening. The receiver antenna, integral with the unit, is augmented by signal pickup on the power line connections and adequate signal strength is available at most locations. This factor also protects the receiver from deliberate screening as an attempt to prevent operation.

Receivers controlling more than one circuit are less flexible in the choice of location. Usually, receivers of this type should be installed at the incoming electric panel; otherwise, a modification to the building wiring will be required.

The application of a radio control system to an idealized distribution system layout is demonstrated in Exhibit VI-2. As referred to earlier, no portion of the power system forms part of the communication channel

EXHIBIT VI-2

and communication between the central control and the individual receivers is maintained regardless of the network configuration. Receivers may be located at any point on the distribution network that is within the service area of the transmitter. Exhibit VI-3 details the major components which are required to be added to an existing distribution network to provide for remote radio control.

The major factors which will influence the cost requirements for a VHF radio system may be summarized as:

- 1) The effective coverage area for a given transmitter and antenna is largely controlled by the surrounding terrain. The load density within that service area will govern the number of controllable loads and therefore the total controlled kW demand per transmitter. Therefore, as the amount of controlled kW demand per transmitter decreases, the cost per controlled kW increases.
- 2) The physical dimensions of the utility's network and the effective service area of each transmitter will dictate the number of transmitters required. A long, narrow service area will be more costly to cover via radio than an equivalent service area which is more "square" or more evenly proportioned. Similarly, a mountainous area will be more expensive to achieve a one hundred percent coverage with a radio communications system than a service area that is relatively flat.

Typically, a 300 watt licensed power transmitter may be assumed to have an average service area of 15 mile radius from the antenna site. This may be increased up to about 25 miles for very flat locations in "quiet areas" but reduced in built-up areas containing large buildings, radiated interference and such considerations which suggest a low signal to noise ratio may be encountered.

REMOTE TRANSMITTER CONTROL
MAY BE MICROWAVE OR
LEASED TELEPHONE LINES

CONTROL RECEIVERS SCATTERED
THROUGHOUT TRANSMITTER SERVICE
AREA.

V. H. F. RADIO CONTROL
COMPONENTS.

EXHIBIT VI-3

- 3) The joint use of existing radio facility towers for load control transmitter antennas is sometimes possible and will reduce the overall cost. In addition, existing transmitter land lines or microwave systems may be available for joint use as a communication link from the control center to the load control transmitter.
- 4) The complexity of the communication link required between the control point and the transmitter is dependent on 2 major factors: 1) the number of transmitters controlled and, 2) the distance from the control point to the furthest transmitter location. An evaluation must be made of the relative capital and operating costs of alternatives such as a master transmitter for controlling the remote transmitters via microwave link or leased telephone lines.

Power Line Carrier Control Using Low-Frequency Injection

Low-frequency power line carrier control has been commonly utilized in overseas markets for many years. The hardware has been continually updated to incorporate new developments in circuitry and solid state devices and the application of new sophisticated electronics has enabled the development of complex signal codes. Equipment is now available with code formats which range between simple on-off rhythm keying and multibit binary pulse codes capable of significant intelligence.

Regardless of the code format used, all systems employ the following basic techniques. The low frequency signal is in the low audio range, usually less than 1000 Hz and above the fundamental 60 Hz power frequency. This signal is generated by a low frequency oscillator and is keyed on-off in accordance with the signal code program. The resultant chopped, low-frequency carrier is injected into the power system in such a manner that it adds vectorially to the power system waveform and modulates the fundamental voltage wave.

Injection may be accomplished in two ways: parallel and series, either line-to-line or line-to-ground. Parallel coupling involves injecting the signal via a line connected capacitor and a 60 Hz filter reactor. Series coupling is by means of a series boosting transformer. In either event, the coupling devices must be large enough to handle the injected kVA, which for estimating purposes may be assumed to be 0.1% of the maximum load on the system: 1kVA per MVA of system load.

The high injection power requirements to obtain a usable signal has, in part, been responsible for this system being restricted to a one way system. Return communication from the receiver to the substation (two-way system) is neither currently provided nor foreseen in the near-term.

The receiver relays at customer terminals possess blocking filters for the fundamental frequency and accept the injection signal frequency. Detectors are pre-programmed to accept a signal code or codes according to the manufacturer's system design-typically between one and three codes.

Significant parameters in the use of low-frequency powerline injection are as follows:

1. Attenuation of the injected signal by the distribution system components will be lower as the signal frequency approaches the fundamental power frequency. This is due to the characteristics of the power system which are designed to transmit fundamental frequency power with a minimum loss. An injected frequency lower than power frequency will cause higher magnetizing currents (therefore, higher losses) in shunt-connected magnetic circuits (transformers). Frequencies higher than power frequencies will encounter higher reactance in series impedances (line reactance, series reactors), and lower shunt reactance due to line capacitance, both resulting in increased signal volt drops. Generally, frequencies below 1000 Hz are sufficiently close to the power frequency to permit normal transformer action in both power and distribution

transformers. Injection at the subtransmission and medium voltage distribution levels is therefore feasible without involving an intolerable reduction in signal strength at the end-use terminals. The closer the signal frequency is to the power frequency, the better the distribution system will perform at the signal frequency.

2. A second consideration is signal losses by mechanisms other than series attenuation. These include direct losses due to shunt connected loads such as power factor correction capacitors which are encountered commonly on distribution systems. Line capacitors are utilized as an integral part of the system for voltage control, and at the end-use terminal for power factor correction. In either event, capacitors exhibit a decreasing shunt reactance with an increasing signal frequency and absorb signal volt-amperes. In addition, as the signal frequency is increased, the lumped capacitive reactance drops while the series line inductive reactance is increased, giving rise to a potential divider effect. Dependant upon the network characteristics and the signal frequency adopted, switching lumped capacitors can cause an unexpected signal decrease or increase.

The use of a signal frequency close to the power frequency to take advantage of the transmission path characteristics, incurs a penalty at the consumers terminal. Each terminal power frequency load also provides a load on the injection signal voltage proportional to the ratio of the signal voltage to the power frequency voltage. Generally, the final choice of signal frequency will be from discrete bands provided by individual manufacturers and will be based upon network characteristics, field tests and measurements and the proximity of other similar carrier current installations where interference may be a problem.

3. Selection of the signal frequency within the audio band considered (less than 1000 Hz) is subject to certain limitations. Although the lower end of the band may be preferred for minimum signal path attenuation and an increase in the area covered, this part of the frequency spectrum is rich

in power frequency harmonics of significant magnitudes. Should such harmonics correspond to the signal frequency, the receivers will be saturated and will be inoperable.

Not only must frequencies corresponding to both even and odd harmonics of 60 Hz be avoided (i.e., 120, 180, 240, 360 Hz, etc.), each of these frequencies must be given a clearance margin to allow for harmonic generation under anticipated "off normal" power system operation frequencies. It is particularly important to allow a safety band below the nominal harmonic frequencies as emergency load shedding may be required under abnormally low system frequency.

In order to limit the effects of line noise, the bandwidth allowed by the injection and receiver filter circuits is narrow. With the low signal frequencies used, the effective bandwidth is limited to only a few Hertz. Consequently, the speed of signal transmission is slow, commonly in the range of 10 to 30 seconds per message. Depending upon the signal coding utilized, each message may contain one or several independent commands.

Signal coding for specific types of equipment is available in each manufacturer's published literature and falls within two basic categories; repetitive and binary pulse. In each case, simple on-off transmitter keying is used, resulting in audio tone bursts of a finite length being injected into the system.

In the repetitive system, tone bursts and spaces are of equal durations and are repeated in a rhythmic fashion to give a recognizable periodic time of the injected rhythm. By changing the period (i.e., the length of the tone signal and space cycle), different addresses are obtained. Receivers are provided with decoders which are preset for a particular periodic time and will operate if the transmitted period corresponds to this setting. Signals of different periodic times will inhibit the output, analogous to a simple pendulum. Only relatively few discrete

addresses are possible at any one signal frequency. One major advantage is that a few of the injected pulses may be missed during the transmission period and the receiver will still obtain an identifiable signal. A dual pulse repetition rate signal may be transmitted sequentially to significantly increase the number of discrete commands available. This form of coding is particularly suitable for systems containing potentially high network noise bursts and where discrete address requirements are minimal.

The binary pulse code configuration uses a multibit mark/space signal. The mark comprises a short duration tone burst of typically 0.5 second. Up to 50-bit signal trains are presently being used for utility application. The subdivision of the train into address and command fields can result in an impressive number of discrete signals (in the order of 20,000). It is important to emphasize that the receiver must detect the complete signal train in order to respond, thus it may be necessary to repeat the command more than once to achieve the same immunity from system noise obtainable with a repetitive type system, at a cost of much longer transmission times.

Generation of illegal codes and injection into local wiring for the purpose of defeating the relay is difficult, giving good system security. By-passing the signal for the purpose of preventing operation would require technical knowledge not available to the majority of the population.

4. Application of the low-frequency injection system requires an electrical engineering analysis of the distribution system. The major factors involved are network configuration, normal and abnormal switching arrangements, circuit impedances (or methods of construction), location and value of shunt capacitors and series reactors, load type and load distribution (geographical and magnitude). The controlling factor, however, will be the local system load at each point selected for injection. This factor determines the injection signal input kVA.

The use of a few, large injection points to cover a distribution area may show a reduction in cost for both the equipment and the communication channel between the control point and the injection sites. However, the optimum rating of each site (and therefore the number required) may be limited by load considerations. Too large a unit looking into a high system impedance may cause an objectional voltage flicker during signal injection, particularly if too great a differential exists between the impedance to the nearest and to the most remote end-use terminal.

Injection may be at either the medium (distribution) or high (transmission) voltage level of the system. The choice will depend largely on the network configuration and area to be covered. Due to the high injection power involved, frequency conversion and coupling equipment is physically large and space must be available either inside the substation building or outside (depending upon the manufacturer's equipment type). In either event, the complexity rises with increasing voltage level of injection as at the higher voltages, a fully protected feeder bay must be used for connection to the bus. Also, an adequate house service electrical supply must be made available.

The location of receiver relays is relatively flexible and simple. The injected signal is available throughout the customers wiring system. As a result, the relay may be located either at the incoming control panel or at the controlled appliance, whichever is convenient. Relays possessing facilities for controlling more than one circuit are somewhat less flexible in location. If not installed at the incoming panel, some modification to the building wiring will be required.

Two possible alternatives in the application of low frequency powerline carrier control to an idealized distribution system layout are shown in Exhibits VI-4 and VI-5. The former diagram shows a typical radially connected network with injection taking place at each bulk supply point's medium voltage busbar. The latter demonstrates the possibility of injection at the high voltage level in order to cover more than one bulk

**L. F. POWERLINE CARRIER CONTROL
MEDIUM VOLTAGE INJECTION**

EXHIBIT VI-4

EXHIBIT VI-5

supply point with a single set of injection equipment, but also indicates the vulnerability of the communication path to switching at the transmission system voltage level. This deficiency is particularly serious where the transmission system is not owned and operated by the distribution authority. Receivers may be located at any point on the system where a low voltage supply is available.

Exhibits VI-6 and VI-7 detail the major components required to be added to an existing distribution network. Although it is apparent that the required equipment has much in common between the two alternatives, it must be recognized that in the latter case, the injection point equipment is larger, is rated for the higher voltages and requires a significant addition to the high voltage substation in the form of a completely protected feeder bay.

Factors which will influence the cost requirements for a low-frequency powerline injection system are summarized as:

1. The demands imposed on the system governs the injection equipment rating. Conversely, the amount of controllable load tied to the injection equipment has no effect on the rating of that equipment. This implies that for any given system, the greater the ratio of controlled load to total load, the lower will be the total cost of the system per controlled kW.
2. Network changes (whether extension of the system, increasing load densities or changes in network switching arrangements) effect the required capacity of injection equipment and tuning. Similarly, projected load additions close to the injection station must be factored into the initial design as these may limit the maximum allowable injection power due to possible voltage flicker problems.

(R) L.F. CARRIER RECEIVER
RELAYS FOR SYSTEM CONTROL
CAN BE LOCATED THROUGHOUT
SYSTEM.

INJECTION POINT COMPRISES:

- 1) FULLY RATED AND PROTECTED
CIRCUIT BREAKER OR FUSE
- 2) SYSTEM VOLTAGE CAPACITOR
- 3) TUNING REACTOR
- 4) ISOLATION TRANSFORMER
- 5) FREQUENCY GENERATOR/CONVERTER

(R) L.F. CARRIER RECEIVER
RELAYS FOR LOAD CONTROL

L.F. POWERLINE CARRIER CONTROL COMPONENTS.

INJECTION POINT COMPRISES:

- 1) FULLY RATED AND PROTECTED
CIRCUIT BREAKER
- 2) SYSTEM VOLTAGE CAPACITOR
- 3) TUNING REACTOR
- 4) ISOLATION TRANSFORMER
- 5) FREQUENCY GENERATOR/CONVERTER.

R L.F. CARRIER RECEIVER
RELAYS FOR SYSTEM CONTROL
CAN BE LOCATED THROUGHOUT
SYSTEM.

R L.F. CARRIER RECEIVER
RELAYS FOR LOAD CONTROL.

**L.F. POWERLINE CARRIER CONTROL
COMPONENTS**

EXHIBIT VI-7

3. A cost comparison of transmission versus distribution level injection should be made for distribution systems having the option of high voltage injection. The cost requirement per injection point increases significantly at higher system voltages. At the same time, the number of injection sites for a given area may decrease. The comparison must also include the cost the required communication channels to each site. The analysis should recognize any additional maintenance charges incurred as well as inherent intangibles (such as expense of visits to the number of sites involved, availability of substation space and additional rate costs incurred by the failure of one injection point).

Power Line Carrier Using High-Frequency Injection

Historically, high frequency injection into power lines has been restricted to applications using open-wire, high-voltage primary transmission lines for the purpose of voice communication, supervisory control and/or protective relay systems. These installations performed well, but were generally bulky and used vacuum tube techniques. Little application was seen on distribution systems due to the large power requirements, cost, and regular maintenance required on both transmitters and receivers. Operating frequencies were generally in the range of 150 to 500 kHz.

Development of solid state components has reduced the size, power, cost and maintenance requirements. As a result, the equipment has become more attractive for use on lower voltage systems. Such equipment is now in advanced, post-development testing phase and is expected to be available as a commercial product in the near future.¹ Studies have indicated that noise generation on low and medium voltage lines is at a minimum at frequencies somewhat lower than those previously used. The band between 5 and 200 kHz has been selected for this application. The signal is generated by a stable solid state oscillator and keyed either on-off or frequency shift in accordance with

a preselected multibit binary pulse code. The resultant modulated carrier may be injected into the power system by parallel or series injection to modify the power frequency voltage wave.

Injection may be either line-to-neutral or neutral-to-ground via a line-connected coupling capacitor and the necessary protective fuses and isolating switches. A high-frequency current transformer may be used for signal injection if applicable. Injection power requirements are low (normally in the order of a few watts), but rise with a decrease in frequency. Low power requirements encourage the use of this system for two-way communication. Such systems are being perfected for the purpose of remote meter reading and other remote data retrieval functions, in addition to load control.

The receivers at the customer terminals are provided with input filters for the carrier frequency. Detector-decoders have been designed for the appropriate signal address and operate function. For remote meter reading, the receivers have an "on-demand", retransmit capability from integral information storage registers.

Significant parameters in the use of high-frequency power line injection are:

1. Attenuation of the injected signal by the distribution system components is relatively high. This is due to the high reactance of system series inductance and low reactance of shunt capacitance at these frequencies. The effective range of the signal is somewhat less than an equivalent lower frequency system and injection is usually limited to the medium voltage distribution system. Adequate signal strength can be obtained to handle the attenuation across medium to low voltage distribution transformers without the use of signal bypass facilities. A wide spread, low-load density medium voltage system may require signal repeaters to achieve adequate signal strength at the remote, low voltage end-use terminals.

2. Signal losses not attributable to power distribution system series attenuation occur principally at shunt connected capacitors which possess a low reactance at the signal frequency. These capacitors may be either voltage correction system capacitors or customer terminal power factor correction capacitors. The former should be provided with signal frequency blocking filters but the latter may be trapped on an "as needed" basis (depending upon the signal conditions prevailing at that particular location).

The use of a signal frequency higher than the power system frequency reduces the signal loss in the power frequency load equipment. Sufficient inductance is usually present in the load equipment to severely limit loading of the signal source.

3. Selection of the signal frequency may be either controlled by the equipment vendor or chosen from within an available band, depending upon equipment type. Precise selection of a frequency in this high band is relatively unimportant. Only a nominal amount of power system generated interference (in the form of harmonics) is present and only wide-band impulse noise is a consideration. There are some advantages to be gained at the lower end of the band: 1) less distribution system signal attenuation and, 2) a minimum interference with the intermediate frequency stages of broadcast band AM radio receivers (conventionally 455 kHz). Disadvantages are higher injection power and increased signal loss in power frequency system loads.

At the signal frequencies used, the band width is sufficient to allow for a moderate transmission speed resulting in short message transmission times using multibit codes. This factor enables the channel to be available for multiple message commands without excessive delays. Typically, up to 150 bit signal trains are used providing the capability for individual address of each meter point in addition to common addresses for group functions.

Security of the system is relatively good. Generation of illegal commands would be difficult while bypassing the signal for the purpose of preventing operation may be partially prevented with the practice of obtaining the signal on the line side of the meter, placing the meter inductance between any bypass tap and the receiver. In addition, if the system was used for remote meter reading, any such bypass would be readily detected.

4. Application of the high-frequency injection system requires a minimum of information about the distribution system concerned. The information needed is limited to such factors as network configuration, normal and abnormal switching arrangements and location of power factor correction capacitors. For load control systems of this type which permit selection of signal frequencies, the type of construction of the distribution system (overhead, underground) would be needed.

Several factors result in a requirement for a minimum amount of application engineering:

1. Each of the systems is predicated upon the use, or facilities for use of remote meter reading. As such, the distribution system is divided into sectors. Each sector reports to an individual sector control unit for signal processing. This is necessary in order to avoid "bottlenecks" in the information channel (where large amounts of data have to be transmitted).
2. Each sector injection unit contains the necessary high frequency equipment. Due to the low transmitted power, such equipment is comparatively small, simple and inexpensive and may be located at a substation or elsewhere on the distribution system.
3. Distribution system impedances at high signal frequencies are unpredictable; therefore, empirical determination of injection points is more expedient. If trouble areas are located during test,

it is relatively simple to relocate the injection point or provide repeaters.

4. The restriction in signal range due to attenuation, plus the use of individual sectors, usually results in injection at the medium or low voltage distribution levels thus rendering the system insensitive to variations that may occur on the high voltage system.

Location of the receiver in the customer's building is, typically, at the metering point. This avoids the signal loss due to the customers wiring and noise generated by end-use devices. The positioning of the receiver (or transponder) at the meter will be necessary if meter information reading is required (present or future).

This will also enable the receiver power supply requirements to be obtained from the unmetered line. Some modification or addition to the building wiring will be required for load control purposes (usually low voltage wiring to an interposing relay).

The application of a high frequency power line carrier control system to an idealized distribution system layout is demonstrated in Exhibit VI-8. Injection is normally at the medium voltage level and although line connected units of low power output are shown, an alternative higher power substation unit is available with some systems. Injection units may use either individual telephone grade lines to connect to the central control equipment or share party lines, depending upon equipment type. Receivers may be located at any point on the system where a low voltage supply is available. Potential for the use of receivers for system control purposes is enhanced by the retransmit capability and the facility for a unique address for each receiver.

Exhibit VI-9 details the major components required to be added to an existing distribution network. By virtue of injection being at the medium voltage level, coupling to the power system can usually be via a simple fused disconnect.

EXHIBIT VI-8

H.F. CARRIER METER UNITS FOR REMOTE CUSTOMERS METER READING AND LOAD CONTROL.

H.F. POWERLINE CARRIER CONTROL COMPONENTS.

EXHIBIT VI-9

The factors which influence the cost requirements for a high-frequency powerline carrier system may be summarized as:

1. For practical purposes, the signal transmitted power is largely independent of the system connected or the controlled system load. Line attenuation or the maximum number of addressable receivers per injection point is normally the limiting factor.
2. Network changes, by virtue of 1 (above), have a minimum effect on an installed system. Increasing load densities, if not accompanied by additional metering points, will not significantly change the signal quality. An existing sector may have to be sub-divided and an additional injection point installed if the total number of meters increases over the maximum address capacity of the existing injection point.
3. The use of multiple injection points involves the use of multiple communication channels between the control center and the injection points. This may be in the form of leased or dial telephone lines. On systems which permit several injection points to employ shared lines, this requirement is reduced. Nevertheless, the lines comprise a significant percentage of the operating cost of the system.

Hybrid System

The hybrid system is an amalgamation of two generic systems; VHF radio and high frequency power line carrier, the two being combined to accentuate the strong points of each.

From both an engineering and operation standpoint, the strength of the radio system undoubtedly lays in its complete independence from the power system configuration and in consequence, the ability to communicate throughout the area regardless of the supply source arrangements, network configuration,

modifications and "off normal" operating modes. A disadvantage is that for multiple functions at the end use customer location, separate receivers must be provided or, alternatively, single receivers with multiple functions must be installed. This latter will involve significant modification to the customers wiring with the attendant problems of compliance with the National Electric Code for older installations, expense, complaints and liability, both financial and legal.

High frequency power line carrier systems, while being less dependant upon system configuration than the low frequency versions, are still sensitive to abnormal system operation, noise and system induced attenuation of signal strength. At the customer's location however, the injected signal is available at any point in his installation and comparatively simple receivers are possible at each controlled appliance location.

In the hybrid system, communication via the VHF radio channel is between the central control and VHF receivers located at each low voltage transformer's secondary connection. In practice, only those transformers feeding a controlled customer would be so fitted. The VHF receiver contains a small, low power, high frequency oscillator and this tone coded signal is injected into the low voltage wiring upon receipt of an appropriately addressed radio signal. The carrier current signal is available throughout the low voltage wiring connected to the transformer secondary. The signal frequency is sufficiently high, typically about 200 kHz, that the severe attenuation across the transformer winding prohibits interference between two adjacent LV transformers and permits unique addresses to be used.

Significant parameters in the use of hybrid systems are:

1. The radio portion of the system may be either a VHF transmitter dedicated for use with the control scheme or may be the utility's existing VHF voice base station transmitter. The tone-coded control signal is compatible for use on a voice channel although small but usually insignificant delays of the control signal may be experienced on a heavy traffic channel.

Installation of a separate radio channel for the system will follow generally those considerations already described for VHF radio systems with respect to land topography, proximity of urban areas, voice communication experience, requirement for multiple transmitters, and the like.

2. Location of the VHF receiver/carrier retransmitter may be varied according to usage. Injection may be made anywhere on the low voltage transformer's secondary wiring. For overhead line construction, it is usually convenient to locate the receiver on the transformer pole and connect it directly to the transformer secondary terminals. Where pad mounted transformers or underground construction is encountered, receivers are available for pad mounted transformer use or alternatively for use at the meter location of any customer fed from the transformer.

Regardless of the receiver location, all customers connected to the low voltage wiring associated with that transformer will receive a usable carrier signal.

3. The coding system presently available will allow up to eight separate commands per transformer secondary and up to thirty-two groups of addressable receivers at the VHF signal level. It may be necessary to separate the commands for similar end-use loads on one transformer secondary to permit sequential load restoration and prevent overloading due to loss of diversity. This will result in an effective number of commands less than the full eight individual commands per VHF receiver.
4. This system can be used to trigger changes in meter registers to accumulate kWh usage by time zones. Depending on the number of commands occupied for load control or metering requirements, spare commands may be available for fire calls or other ancillary service functions.

The application of hybrid radio/high frequency powerline carrier control to an idealized distribution system layout is shown in Exhibit VI-10. With only the low voltage distribution wiring forming part of the communication channel, the

EXHIBIT VI-10

system is to all practical purposes immune to distribution network considerations. The VHF receiver/carrier current retransmitters may be connected to any low voltage transformer secondary winding circuits which are located within the transmitter service area. Carrier current receivers are located at the controlled equipment in the customers building. The use of hybrid receivers for the control of network apparatus is possible but would have no benefits over a simple radio receiver.

Exhibit VI-11 details the major components required to be added to an existing distribution network. The VHF transmitter may be for the sole use of the control system or alternatively, may be joint use of an existing base station.

Factors which can influence cost for the hybrid system may be summarized as:

1. Joint use of the existing VHF voice communication system and the hybrid load control system can effect substantial savings in procurement, operation and maintenance of the radio portion of the link. However, this saving is at the expense of possible delays in control signal transmission for heavy traffic radio channels. If a separate radio channel is used cost sensitivities are similar to those discussed under the VHF radio control system.
2. The hybrid system's major economic justification hinges on the number of controlled end-use loads being fed from the secondary of each low voltage transformer. As each end-use customer being controlled must share the transformer receiver/retransmitter cost, the economics are quite sensitive to the number of controlled customers per transformer. Each customer is allocated the cost of the carrier current receiver plus the appropriate proportion of the VHF receiver. This sensitivity suggests that the hybrid system is more suited to urban/suburban areas. This system, however, is quite compatible with the radio system. As a result, a combination system approach may be very attractive to the utility serving a mixed urban and rural service area. By applying the hybrid receiver/retransmitters to the urban transformers with a sufficient

REMOTE TRANSMITTER CONTROL
MAY BE MICROWAVE OR
LEASED TELEPHONE LINES

V.H.F. RADIO RECEIVERS CONVERT
SIGNAL TO H.F. POWERLINE CARRIER
FOR ONWARD TRANSMISSION TO
CUSTOMER'S RECEIVER.

V.H.F. RADIO RECEIVERS LOCATED ON
EACH L. V. DISTRIBUTION TRANSFORMER
SECONDARY FEEDING A CONTROLLED
CUSTOMER.

H.F. CARRIER RECEIVER
FOR METERING FUNCTION

H.F. CARRIER RECEIVERS
FOR LOAD CONTROL

HYBRID CONTROL
COMPONENTS.

EXHIBIT VI-11

number of controllable loads, and radio receivers directly to the balance of end-use loads to control, the combination system could optimize both the functional utility and cost of the control system.

3. Network changes have a minimum effect on an installed system. For all practical purposes, the communication channel is independent of the configuration of power system. The exception is that portion of the system which utilizes the low voltage transformer secondary connections (however, this is so insignificant that it may be neglected). By similar reasoning, power system faults can only incapacitate small portions of the control system.
4. Location of the carrier current receivers within the customer's building is simple because the signal is available at all power outlets. The receivers may be installed directly at the location of the end-use appliance with only a minimum wiring modification involved.

Telephonic and Direct Wire Systems

Direct wire supervisory control systems have been used for a number of years for utility and industrial applications with much success. Systems using this form of communication have ranged from simple DC "on/off" switching or polarity change detectors for distribution system control to sophisticated high-speed, digital-coded signal systems for complete system control, indication and metering. The communication path used was commonly privately-owned overhead lines, multiconductor cables or for the high speed systems, leased telephone lines. Where telephone lines were used for the DC type systems, care had to be taken to ensure such routes contained all metallic circuits. One common characteristic of these systems is that they are limited to a few discrete terminals by virtue of the cost of providing unique circuits to each location from the control point.

It follows, therefore, that the installation of direct wire lines for control of end-use utility customers' electrical loads would be uneconomic. However, the presence of the local telephone company's system does provide an equivalent facility which should not be ignored. This network presents an available, reliable and high quality communication channel which enters the vast majority of end-use customers' property. The telephone network can be extended to cover additional locations within the telephone service area at a minimum cost to the utility. Load control schemes using such telephone circuits on a shared basis are in the pilot project/test stage.¹ Such schemes have characteristics compatible with the general purpose automatic dial telephone system. These systems are available for use as one-way or two-way channels for automatic remote meter reading as well as control of end-use customer loads.

In general, these systems share a common feature with other two-way systems; a dependence upon the central control to initiate an information interchange. End-use transponders may independently accumulate data, but cannot transmit this information except in response to an interrogation signal. This places the sole address capability at the telephone switching office equipment. It also greatly simplifies the end-use terminal. Message priority is the sole prerogative of the initiating terminal.

Both circuit impedance modification and tone-coded, frequency-shift signals are used according to the system type. It should be noted that only the latter possesses the capability of transmission through a carrier link.

Scanners for line interrogation are located at the telephone switching office. In some locations, existing equipment installed for routine telephone functions may be utilized. Although sufficient installations are not available to detect any trend at this time, it is quite possible that such equipment will remain under the control of the telephone company.

For one-way load control use, the instruction is received by the end-use receiver and converted to an "on/off" function for the control circuitry. For a two-way system, in addition to receiving the load control signal, the unit

will respond upon demand, and transmit to the central control, information fed to it by the meter encoders (or other sensors as applicable). One-way meter reading encoders are only capable of conveying information back to the control centers.

Significant parameters in the use of telephone systems are as follows:

1. These systems are completely immune from any effects of the operation of the electric distribution system. Although power is required for some customer use terminal receivers or transponders, built-in carryover batteries can be provided to preserve its function. Monitoring the supply status (i.e., on AC or DC power), can be used to retransmit signals to the central control indicating the geographical extent of power outages.
2. Choice of communication system is limited in part, by the telephone company line equipment. DC signaling and line impedance modification type systems both require circuits suitable for the transmission of DC current and as such can only be used on continuous metallic circuits from the exchange main frame to the customer's terminal. Such circuits may contain loading coils but must be free of transformer coupling and similar isolation devices. Any use of carrier circuits or other multiplex links will render these systems inoperable. Tone-coded signals are compatible with all types of equipment commonly found on telephone networks. This coded format also enables individual customer addressing on multi-terminal shared lines.
3. Should the present experience in trial installations of telephone control systems persist in the future, the predominate cost may be expected to be on a per line interrogation charge basis (analogous to the telephone per call charge). The implication of this is to encourage the development of hardware capable of reducing the number of calls required to achieve an end function. Generally, the higher the per call charge, the more the incentives will be to restrict the number of control signals sent, the

bottom line being a cost trade off between the call charge and the price of the logic hardware required to restrict the number of calls. An example of this is shown for two common types of controlled load. End-use appliances containing sufficient storage time may be switched directly for both the "off" and "on" inhibit function, thereby restricting the time off to the period of maximum benefit. Loads which require cycling during periods of control will force cost penalties as the multiple commands per control period would involve multiple charges for the use of the communication channel. To reduce costs, such cycled appliances may be provided with a local logic pretimed program activated once per day when demand control is required. After receipt of such a signal, the device reverts to the preset sequence of "off/on" cycles for a fixed elapsed time period, or possibly, as monitored by outside temperature, as may be appropriate.

The use of this control procedure, while reducing cost, will result in longer outage periods (more hours of control) and possibly more customer complaints.

4. Service is available only where connection can be made to a telephone line. It is expected that a small percentage of electric service customers will not have a telephone communication. In those instances the cost of telephone service installation must be added to the control system cost if the connected load warrants control (or if remote meter reading is required).

Similar considerations apply when the control system is extended to cover the monitoring and/or control of distribution equipment such as capacitors or voltage regulators. In this instance, telephone line connection would be required at each control or monitored location.

5. Although not classified as a load control system, a one-way remote meter reading facility using the telephone network may be a valuable addition to a load control scheme. The combination of a scheme to report back to

the control center plus a one way control system may provide a versatile, low cost combination for areas where a fully automatic two-way system may not be justified.

6. The location of equipment in the customer's property is flexible in that the meter encoders may be remote wired to the transponder. Similar remote wiring will be needed between the unit and the controlled end-use load. Encoders for one-way remote metering are located on the meter to be read and are wired to the telephone line incoming termination.

All wiring within the property is exposed to customer interference. While the load control function may be defeated relatively easily, interference with the meter reading function will be readily detected.

The application of a telephone address control system to an idealized distribution system layout is demonstrated in Exhibit VI-12. As no portion of the power system forms part of the communication channel, communication between the control center and the individual receivers is maintained regardless of network switching or abnormal operating routines. Receivers may be connected at any at any location serviced by the telephone company without further addition to the telephone distribution system.

Exhibit VI-13 details the major components required for telephone control. Except for the customer located receivers, no additions or modifications are required to the distribution network, all equipment being located at the control center and the telephone company's central office.

Factors which influence the cost requirements for a telephone type system are difficult to summarize as the responsibilities shared between the various interested parties may vary widely. No firm trends are yet established but the following possible alternatives are examined.

EXHIBIT VI-12

ADDITIONAL TELEPHONE LINES
REQUIRED FOR POWER LINE
MOUNTED EQUIPMENT

TELEPHONE CO.
CENTRAL
OFFICE

TELEPHONE CO.
DISTRIBUTION
SYSTEM

CENTRAL OFFICE COMPRISES:
1) CONTROL UNIT
2) CENTRAL OFFICE SELECTOR
3) DATE TERMINAL

RECEIVERS AND/OR
TRANSMITTERS SEPARATE
FROM CUSTOMERS
'PHONE

TELEPHONE ADDRESS CONTROL
COMPONENTS.

CONTROL
CENTER

EXHIBIT VI-13

1. The most capital-intensive alternative for the electric distribution utility will occur where the electric system provides all end-use customer equipment, the control center equipment and the telephone office data terminal. It is regarded as unlikely that the telephone company would permit outside ownership of office-installed test selectors or similar line scanning devices connected directly to the exchange main-frames.
2. Another possibility is that the telephone company will provide all the central station equipment, including the central controller, line selectors and data terminal. In this case, the electric distribution utility would provide end-use customer equipment and installation. The telephone company would also provide interconnection facilities for the utility's billing computer (to read from the central office data terminal) and such other access facilities needed for load and distribution system control.

Capital charges would be minimal with correspondingly higher per call rate charges. Responsibility for utilizing any additional capacity (such as reading water or gas meters) would be a joint effort of all parties concerned with the unavoidable coordination problems.

The most simple variation would be for the telephone company to own, install and operate the entire system, including end-use customers' equipment. The control of the system, as to when a meter was read, when a load was disconnected, would naturally be at the sole discretion of the utility.

This approach is uncommon by today's methods of load control and system operation, but it cannot be dismissed without study. Should the system be so organized, the telephone company would sell a complete service not limited to the electric power utility, but including the gas department, water authority, security services, and any other customer for which this communication channel could perform a function, up to the limit of the capacity of the equipment. Charges in the form of a usage charge would predominate (with perhaps an initial connection charge) and all could

benefit from the diverse use of the system. Capital charges incurred by the utility would be minimal, limited to a central controller, any required telemetering and perhaps the contactors necessary for controlling full-voltage end-use equipment.

Direct Vendor Cost Components by Generic Type

In considering the wide range of sizes and types of communication and control equipment to categorize, associated costs are difficult to quote in any generalized manner. Some components of a certain system may have become standardized, while other hardware is still in the development process. Some vendors provided hard, list price quotations, but others were less firm on price quotes because of either the cost sensitivity of matching the system components to a utility system configuration or the competitive nature of the load control market.

In addition, certain costs were given as currently available while others were target priced for future full-production costs and for some systems, sufficient cost information was not provided to render a fair cost range.

In short, load control system hardware costs were not found to be stable enough to provide firm quotes on component prices at this time. New entries into the market, as well as the demand for such systems, will continue to influence the market price. To preserve the usefulness of this section, the major components which make up each generic system type are listed so the reader may seek current vendor quotes on components required to meet his needs. The components listed should correspond to any vendor-proposed system make up. In order to provide a benchmark set of cost comparisons for the various generic systems, Appendix A sets examples of the cost requirements on four case studies.

VHF Radio

- 1.0 Central control unit - The central control unit cost is a function of the utility's control philosophy (i.e., required flexibility in cycling

control periods relative to appliances controlled). For a completely automated system, the central control unit must have the capability to monitor load conditions throughout the system and initiate a control period at a predetermined load level. Less expensive and manually initiated units are also available primarily for small installations.

- 2.0 Radio transmitters - The maximum rating of radio transmitters for this use allowed by the FCC is 300 watts. These transmitters are of standard vintage.
- 3.0 Radio receiver switch - The common, single-function audio tone receiver is available from several manufactures. Multifunction units are also available at smaller production levels. Coded tone receivers are available at higher costs but have more versatile functions and address capabilities. One receiver per controlled appliance is normally required, however, the multifunction receiver can control several appliances per location.

Power Line Carrier Using Low-Frequency Injection

- 1.0 Central control unit - The central control unit cost is a function of the utility's control philosophy (i.e. required flexibility in cycling control periods relative to appliance types), and the total number of appliances controlled. For a completely automated system, the central control unit must have the capability to 1) monitor load conditions throughout the system 2) initiate a control period at a predetermined load level. Less expensive and manually initiated units are also available primarily for small installations.
- 2.0 Signal injection equipment - Costs for injection equipment are a function of the power line voltage at the point of injection. Signal injection at high voltage levels is significantly more costly than signal injection at low voltage levels.

Consideration must be given to the number of injection stations as well (high voltage injection requires fewer injection stations versus low voltage injection which generally requires numerous injection stations). To summarize cost trade offs of this function, high voltage injection requires few injection stations at high costs per station versus low voltage injection requiring several injection stations at lower cost per station.

- 3.0 Receiver and control relay - Both functions are considered jointly as they are performed by a single piece of hardware. There are two distinct types of receiver switches: 1) electro-mechanical, 2) solid state. Electro-mechanical relays have been standard in overseas installation for three decades. Such production processes have been refined and reflect low costs per unit. Solid state receiver switches are relatively new with higher production costs per unit. Multi-function receivers are available at increased costs.

Power Line Carrier Using High Frequency Injection

- 1.0 Central control unit - The incorporation of meter reading capability into the system places additional requirements of flexibility and capacity on the central control unit. A manual central control unit could not meet such requirements, the solution is a fully automated unit of significant cost.
- 2.0 Sector signal injection equipment - For practical purposes, the power of the transmitted signal is largely independent of the connected or the controlled system load. Line attenuation or the maximum number of addressable receivers per injection point is normally the limiting factor.

Network changes, by virtue of (2) above, have a minimum effect on an installed system. Increasing load densities, if not accompanied by additional metering points, will not significantly change the signal

quality. If the total number of meters increases over the maximum capacity of the existing injection point, an existing sector may have to be sub-divided and an additional injection point installed.

- 3.0 Customer's receiver, control relay, encoded message transmitter - These functions are generally incorporated into a single piece of hardware. Solid state construction is utilized, and is anticipated to keep costs down at full production levels. Each receiver is capable of controlling more than one appliance, however, an additional control relay may be required for each new appliance.
- 4.0 Customer's meter reading encoder - The methods for encoding the consumers kWh usage vary among vendors; however, the costs per unit are similar because of the competition between vendors.
- 5.0 Sector encoded message receiver - This function may be incorporated into a common unit with the sector signal injection equipment and will reflect similar cost sensitivities.

Hybrid-Radio/Power Line Carrier

- 1.0 Central control unit - This unit comprises the master controller for tone-code generation and a mini computer for telemetered bulk supply point information and readout. Prices of the master controller depend upon the facilities required. The mini computer prices depend on the number of remote telemetering points as well as the degree of automation in issuing system commands.
- 2.0 Radio channel - Compatibility of the control system with a regular VHF two-way voice system permits the use of existing radio facilities for this portion and no additional charges are involved if this option is taken. The widespread use of land mobile communications may reduce the need to provide a separate transmitter purely for load control purposes to such considerations as traffic density or security.

- 3.0 Radio receiver, power line carrier retransmitter - These functions are performed by one device. The units may be pole mounted for overhead distribution system or mounted on a customer's meter base to cover underground systems. One unit will receive a transmitted signal and retransmit to all customers served by one transformer.
- 4.0 Power line carrier receiver, control relay - These receivers are suitable for the control of a single appliance. A variation of this device is available with customer override facilities at an additional charge.

Telephonic and Direct Wire Control

- 1.0 Telephone Office Equipment - This equipment consists of a central control unit (to act as the interface between the electricity personnel and the telephone system), the central office selector (for originating the calls) and the data terminal (for receiving and storing the transmitted information from the customer's meters and subsequent retransmission to the utility's billing center).

This set of equipment would be, in all probability the responsibility of the telephone office. Costs are expected to vary from office to office according to the availability of existing suitable equipment. Costs would appear not as direct costs to the system but as installation and call charges on an ongoing basis. In trial installation tests, a flat fee has been charged similar to the per circuit installation charge levied for the connection of leased circuits.

- 2.0 Customer's Installation - This hardware consists of the meter encoders, transponder and the necessary contactor equipment for full voltage controls.

Indirect Non-Vendor Cost Components by Generic Type

In addition to those vendor quoted items listed in previous pages, the investigation surfaced a set of less obvious, but additional costs to be borne

by the utility, associated with each generic type of load control system. Non-vendor costs include installation and support equipment costs which may make up a significant portion of the total system costs.

VHF Radio

1.0 Support equipment - Supply point telemetering is required on a sufficient sample of the total load so as to enable an accurate estimate of system demand.

2.0 Communication links:

2.1 Remote RF transmitters - There are several communication channels which can be adapted to this function. Telephone, microwave, and VHF radio are all possible alternatives.

Existing telephone lines are easily adapted to form this communication link. Direct costs are minimal. However, the costs of leasing lines may account for a large percentage of the ongoing operating expenses.

Microwave and VHF radio communication links require substantial direct costs with a minimum of ongoing expenses.

2.2 Supply point telemetering - Generally, the most economic method of interconnection for the telemetering system (substation to control center) will be by means of leased telephone lines.

3.0 Installation and Maintenance:

3.1 Central control and telemetering installation and maintenance - The magnitude of the work involved in the installation of the central control equipment will depend upon the complexity of the control to be used. Actual installation costs of the major pieces of equipment

should not vary significantly as these will be received as self-contained, freestanding units. Interconnection costs will vary with the amount of external devices, control points, remote alarms, telemetering, etc. Installation of telemetering transmitters at the bulk supply points will vary between the extremes of adding transducers to existing potential and current transformer wiring and the procurement and installation of complete metering units where suitable existing facilities are not available.

Maintenance of this equipment is limited to periodic cleaning and inspection. Trouble diagnosis and repair requirements should be infrequent and are expected to be relatively straight forward.

- 3.2 Transmitter installation and maintenance - As the use of VHF two-way voice communications by electric utilities is now almost universal, it is assumed that a transmitter site, housing and antenna tower is available for the installation of the load control transmitter and the antenna. Installation charges would be therefore limited to man-hour charges incurred in placing the transmitter cabinets, wiring power supply and control circuits, antenna erection and running the antenna co-axial feeder. Experience with similar voice transmitters has shown startup and adjustment requirements to be minimal. The only remaining initial charges are those associated with the FCC licensing application preparation.

Maintenance charges are minimal, the manhour requirements are on the order of one visit per month for cleaning, inspection and possible minor adjustments.

- 3.3 End-use receivers - The receiver switch installation costs will vary with each placement. Locating the switch at the service entrance panel board requires some rewiring. This may require the hiring of contract electricians to meet the minimum standards prescribed by the National Electric Code. However, where installation is adjacent

to the controlled appliance, the use of utility personnel will lower the total costs. The maintenance of receiver switches is effected in a similar manner to meters. A faulty receiver is generally changed out and replaced with a new unit. Tests are performed on selected components which are easily replaceable if found to be defective, otherwise the unit would be discarded.

4.0 Initial Test and Debugging

This function would comprise initial transmitter setup adjustments, modulation and loading adjustments, and verification that the transmitter is operating within the limits imposed by the FCC station license. Initial tests are required to calibrate the telemetering equipment. A check of the operation of the central control equipment for correct operation codes for each command is also necessary. Where multiple transmitters are utilized, sequential operation should be verified to ensure that no mutual interference is present.

It is not anticipated that extensive field strength measurements would be required or that customer installation tests would require more than a few random samples.

Power Line Carrier Using Low-Frequency Injection

1.0 Support Equipment:

- 1.1 Supply point telemetering is required on a sufficient sample of the total load so as to enable an accurate estimate of system demand.
- 1.2 Injection equipment - In addition to the electronic portions of the injection station (i.e. tone generators, signal processors etc.), the injection equipment includes the power line coupling components, the isolation transformers, capacitors, tuning inductors, circuit connection devices and protective systems. The two latter devices

are not included as part of the purchased load control equipment. According to the voltage at the point of injection, these connection devices may range from a fuse disconnect to a fully protected feeder bay at a major switchyard and comprising the required bus bars, circuit breaker, disconnects, protective relays, etc. Connection from the system to the injection equipment may involve overhead jumpers or, more commonly, insulated cables running from the system connection device location (breaker, fuse) to the location of the injection equipment.

According to the manufacturer's design specification, the injection equipment may be suitable for either indoor or outdoor installation. If the equipment is of the indoor type, building space must be available or constructed. If the outdoor type is required, the associated mounting slabs and support structures will have to be provided.

2.0 Communication Links:

- 2.1 Remote injection stations - There are several communication channels which can be adopted to this function. Telephone, microwave, and VHF radio are all possible alternatives.

Existing telephone lines are easily adapted to form the communication link. While direct costs are minimal, the costs of leasing lines may account for a large percentage of the ongoing operating expenses.

Microwave and VHF radio communication links require substantial direct costs with a minimum of ongoing operating expenses.

- 2.2 Supply point telemetering - Generally, the most economic method of interconnection for the telemetering system (substation-to-control center) will be by means of leased telephone lines.

3.0 Installation and Maintenance:

- 3.1 Central control and telemetering, installation and maintenance - The magnitude of the work involved in the installation of the central control equipment will depend upon the complexity of the control to be used. Actual installation costs of the major pieces of equipment should not vary significantly as these will be received as self-contained, freestanding units. Interconnection costs will vary in relation to the amount of external devices, control points, remote alarms, telemetering, etc. Installation of telemetering transmitters at the bulk supply points will vary between the extremes of adding transducers to existing potential and current transformer wiring and the procurement and installation of complete metering units where suitable existing facilities are not available.

Maintenance of this equipment is limited to periodic cleaning and inspection. Trouble diagnosis and repair requirements should be infrequent and are expected to be relatively straight forward, with the possible exception of the more complex multi-command coded equipment.

- 3.2 Injection equipment - This equipment includes the installation of support equipment, the injection equipment and provision of a station auxiliary power supply adequate for the required injected power (in the order of 500 kVA for a 500 MW controlled system). Maintenance charges would be comparable with normal power system maintenance requirements for equivalent size equipment.
- 3.3 End-use receivers - Receiver switch installation costs are a function of placement (i.e. at the service entrance panel board or adjacent to the controlled appliance). Installation at the service entrance panel board, almost mandatory for multi-function receiver switches, requires rewiring of the supply circuit to the end-use appliance. This policy may require the hiring of contract

electricians to meet the minimum standards prescribed by the National Electric Code. Installation adjacent to the controlled appliance may be effected by utility personnel at a lower cost.

Maintenance costs at this stage of development of domestic projects are largely indeterminate. Due to domestic labor rates, it is anticipated that receiver switches would be handled in much the same manner as existing customer meter practice.

4.0 Initial Test and Debugging:

Initial testing comprises checking the operation of the injection equipment and adjusting the tuning inductors for the required signal level with the distribution network in the normal operating configuration. Initial tests are required to calibrate the telemetering equipment and check the central control equipment for correct operation codes for each command.

Signal strength measurements are normally limited to a few sample points on each system fed by an injection point, concentrating on feeder ends or locations downstream from line capacitors or installations of large power factor capacitors. Areas where high line noise is detected should be examined for adequate signal strength or correction of the noise problem.

Individual testing at each customer installation is not considered necessary.

Power Line Carrier Using High-Frequency Injection

1.0 Support Equipment:

1.1 Supply point telemetering is required on a sufficient sample of the total load so as to enable an accurate estimate of the system demand.

- 1.2 Connection equipment required for each unit is a function of the location of the installation. The appropriate equipment is detailed in the installation section.

2.0 Communication Links:

- 2.1 Sector injection equipment - The use of multiple injection stations involves the use of multiple communication channels between the control center and the injection stations. This may be in the form of leased or dial telephone lines. On systems which permit several injection points to employ shared lines, this requirement is reduced. While direct costs of such communication links are minimal, associated ongoing costs may account for a significant portion of total operating costs.

Due to the large number of injection stations, microwave radio would not seem to be an economical solution for this function. VHF radio may be an economical answer, noting the direct costs of such a system are significant and operating costs are minimal.

- 2.2 Supply point telemetering - Generally, the most economic method of interconnection for the telemetering equipment (substation-to-control-center) is by means of leased telephone lines. If two-way meter reading facilities are provided by the control system, then the telemetered bulk supply point quantities may be transmitted over the remote meter reading channel, providing sufficient time is available in the meter reading program for the repetitive interrogations required for this function.

3.0 Installation and Maintenance:

- 3.1 Central control and telemetering, installation and maintenance - Should the high-frequency power line carrier equipment be used for load control purposes only, the installation costs of the central

control equipment would vary according to the complexity of the control desired. However, the variance should be in the same order of magnitude as other one-way systems. Such variations would be minimized due to the major pieces of equipment being supplied as self contained units. The difference is due to the variations in the number of interconnections to external devices. If, on the other hand, a full two-way, remote meter reading and control system was involved, the installation costs would rise sharply. These costs would include not only the remote telemetering cabinets but the computer required for the meter reading program, address capability, retrieval of the meter reading and subsequent processing prior to transferring the information to the appropriate billing computer.

Installation costs for the telemetering transmitters at the bulk supply points will vary between adding transducers to existing potential and current transformer wiring and the procurement and installation of complete metering units where suitable existing facilities are not available.

Maintenance of the equipment is limited mainly to cleaning and inspection. Trouble diagnosis and repair requirements should be infrequent with a one-way control system but significantly increasing in frequency and complexity with the two-way system.

- 3.2 Injection equipment - Due to the limited range of the high-frequency signal, the majority of applications will result in the injection point being located on the medium voltage system and covering one or at the most, a few feeders from one distribution substation. Two basic injection locations must be considered, at the substation bus bar or on a feeder remote from the substation.

Where the equipment is installed within a distribution substation, space must be provided together with the required system connection equipment (circuit breakers, fuses, etc. as necessary). The

installation, must be designed in such a manner that the control equipment does not hazard the substation bus. The fault interrupting duty at this location will often dictate the use of protective devices in excess of the rating needed for the injection equipment. However, equipment in this location will frequently service a large number of end-use receivers.

Problem areas discovered after installation due to line attenuation, capacitors, and similar causes of poor signal strength, should be cured at the individual trouble spots by repeaters, traps, etc. because of the costly alternative of moving an injection point.

Feeder-mounted equipment generally covers fewer end-use receivers per injection point. This equipment is small and installed simply on an existing line pole. Coupling to the line, with a fuse and surge arrestor, is inexpensive and the existing feeder protection may be used as backup without hazarding an appreciable portion of the power system. The somewhat unpredictable performance of the power system at the signal frequencies is less of a potential problem as the pole location of the injection unit may be easily and inexpensively changed if trouble is encountered. Not all equipment available may be suitable for line installation.

- 3.3 End-use receivers - The use of power line carrier permits the receiver to be located at any point on the customer's wiring. The signal is present wherever electric service is available. However, the use of the receiver unit for retransmitting the local meter reading requires that the unit be installed at the customer's meter location. Current designs are compatible with the single phase house service meter socket. The units are fitted as an extension of the plug-in meter base. Connections from the meter position to the end-use load location are required in the form of low voltage "thermostat" wiring. Additional contactors are required where full

voltage end-use load are to be controlled. This wiring technique will reduce the total installation costs by minimizing changes to the customers wiring.

Maintenance for receivers would be handled in a similar manner to the existing house service meters (i.e. a changeout program). Charges would be due to time, transport and the provision of suitable repair facilities. Faulty meter encoders for the two-way system could be changed in the field, but it is questionable if this action would be advisable. Injection units installed in substations would be subjected to periodic maintenance and local repair at that location is possible. Pole-mounted units would be replaced by a spare and the faulty unit would be returned to the service facility for repair.

4.0 Initial Test and Debugging

Initial testing comprises initial injection equipment setup and adjustments would be minimal. Tests are required for each command for one-way systems to verify the correct operation of end-use receivers and spot field measurements would be required at selected points covered by each injection unit.

Systems with two-way facilities would require extensive initial software verification followed by an individual address signal and reply to ensure correct response and processing. Any receiver failing to respond would require site investigation at the end-use location or the injection unit.

Telemetry calibration would be required on each circuit provided from the bulk supply points.

Hybrid Radio/Power Line Carrier

1.0 Support Equipment

Supply point telemetry is required on a sufficient sample of the total load so as to enable an accurate estimate of the system demand.

2.0 Communication links; Remote RF transmitter

- 2.1 There are several communication channels which can be adapted to this function. Telephone, microwave, and VHF radio are all possible alternatives.

Existing telephone lines are easily adapted to form this communication link. While direct costs are minimal, the costs of leasing lines may account for a large percentage of the ongoing operating expenses.

- 2.2 Supply point telemetering - Generally the most economic method of interconnection for the telemetering system (substation to control center) will be by means of leased telephone lines.

3.0 Installation and Maintenance:

- 3.1 Central control and telemetering, installation and maintenance - The magnitude of the work involved in the installation of the central control equipment will depend upon the complexity of the control to be used. Actual installation costs of the major pieces of equipment should not vary significantly as these will be received as self-contained, freestanding units. Interconnection costs will vary in relation to the amount of external devices, control points, remote alarms, telemetering, etc. Installation of telemetering transmitters at the bulk supply points will vary between adding transducers to existing potential and current transformer wiring and the procurement and installation of complete metering units where suitable existing facilities are not available.

Maintenance of this equipment is limited to periodic cleaning and inspection. Trouble diagnosis and repair requirements should be infrequent.

- 3.2 Transmitter installation and maintenance - as the use of VHF two-way voice communications by electrical utilities is now almost universal, it is assumed that a transmitter site, housing and antenna tower is available for the installation of the load control transmitter and the antenna. Installation charges would be limited to man-hour charges incurred in placing the transmitter cabinets, wiring power supply and control circuits, antenna erection and running the antenna coaxial feeder. Experience with similar transmitters has shown startup adjustment requirements to be minimal. The only remaining initial charges are those associated with the FCC licensing application preparation.

Maintenance charges are small. Manhour requirements are on the order of one visit per month for cleaning inspection and possible minor adjustments.

It should be noted that, none of these transmitter related costs are applicable if the existing radio communications facilities is utilized for the radio portion of the hybrid scheme.

- 3.3 End-use receivers - Receiver installation costs are low due to the facility for location adjacent to the controlled apparatus. Such installations may be performed by utility personnel.

Installation of the VHF receivers will involve the use of a service line crew for pole-mounted units.

Maintenance of both end-use and VHF receivers is assumed to be on a change-out basis, where the malfunctioning unit is replaced by a spare unit. Tests are performed on selected components which are easily replaceable if found defective, otherwise the unit would be discarded.

4.0 Initial Test and Debugging

These tests would be similar to those for a radio system with respect to the radio transmitter, control, telemetering and field strength measurements.

Verification that the VHF receiver is retransmitting the command over the low voltage transformer secondary wiring is required. A portable, low-power VHF test set is available to test for code injection and check of the customer's receiver function. A single test per VHF receiver should be sufficient unless trouble is encountered.

Telephonic and Direct Wire

Non-Vendors costs are largely indeterminate at this time. These non-vendor costs are subject to numerous and significant variables. While the end-use customer installation charges may be on the same order of magnitude as other load control systems, the low capital cost of this system is compensated for by usage charges.

Trials to date have resulted in a variation of charges based upon a per line interrogation for each meter reading command or each load control signal. No meaningful estimate of the charges can be made at this time because of the variation in charges according to location and the difference in equipment supplied by the telephone company (ranging from the central office selector only to the complete equipment, including the customer's installation). An estimate of the actual charges must be made for each specific location.

Maintenance charges should be restricted to those incurred by a customer's equipment changeout program and return of the faulty units for inspection and repair. Should the telephone company operate the entire system on a lease basis, maintenance charges would be included in the rate charge.

SECTION VI - FOOTNOTE

1. J. A. Serfass, R. K. Adams, H. M. Long, "Field Demonstrations of Communications Systems for Distribution Automation". IEEE 1978 Region Six Conference Record. Electronics in Resources Management, Alamogordo, New Mexico.

IEEE Catalog No. 78CH1316-9 Reg. 6, p. 36-42.

SECTION VII

PHYSICAL DISTRIBUTION SYSTEM FACTORS AFFECTING THE APPLICATION

The purpose of this section is to describe the factors which limit or enhance the choice of one system over another. Differences exist between the types of equipment available for load control but for simplicity, the systems can be categorized generically in terms of the communication path employed. As reviewed in this section, five separate system types will be analyzed with respect to design and application differences which must be recognized in the selection process.

Choosing the system (or systems) best suited for a specific utilities' application requires a characterization of the present physical network and an awareness of the future configuration as projected by the planning program. The type of service area, bulk supply arrangements and distribution system characteristics as they exist and as they will develop due to system reinforcement, customer shifts and area load growth are examples of the considerations which may influence the selection of a load control type.

No less important in this selection process is the examination of the available auxiliary (or complementary) functions which may accrue due to the use of any given load control device and the application to the distribution network. Typical functions normally associated with one-way control systems are power factor (line regulation) capacitor switching, line regulator control for load shedding by voltage reduction, time-of-day meter register switching, display lighting/street lighting control and fire department calls. Two way systems offer a wider selectivity in auxiliary usage in as much as verification of the action initiated is feasible. Thus, not only can the functions described for one way systems be achieved with positive feedback of the action if so desired, other actions are possible. These may include customer remote meter reading, system data collection (substation meter reading), system switching and fault location. In each case, the needs and desires of a given

utility system must be rationalized on the basis that the more functions that are required, the more complex will be the control system and the more difficult will be the message protocol within the control strategy in order to ensure system priorities are protected.

The five generic types of technology available for near term load control as characterized in this section are:

1. VHF Radio remote control of end-use loads via a 1-way link from area transmitters to locally-installed receivers using F.C.C. controlled frequency bands.
2. Low-Frequency Power Line Carrier 1-way control of end-use loads via a signal in the low audio range (usually less than 1 kHz) injected onto the power line and modulating the fundamental voltage wave.
3. High-Frequency Power Line Carrier systems operating with a signal frequency between 5 kHz and 200 kHz which is injected into the power system as a modulated carrier. Although commonly two way systems, one way operation is available with the possibility of expansion into two way operation at a later date, if desired.
4. Hybrid Radio/High Frequency Power Line Carrier systems combine radio transmission to low voltage transformer mounted receivers with a carrier signal in the 200 kHz range injected into the service cable to control the end-use loads of customers.
5. Telephone and Direct Wire systems for 2-way control and communication with end-use loads utilizing telephone company owned or similar dedicated lines as the prime communication path.

The factors to consider in the selection of a load control system are based on the many aspects of the distribution network. Certain points are suggested for guidance but local requirements, operating methods and unique situations may modify the overall picture for any given application.

Type of Service Area

The first major aspect to recognize in selecting the type of equipment best suited for a distribution system is the type of service area. The general topography and customer density of the area served by any distribution utility impose parameters that will influence the choice of the available communication channels for load control. Three general categories of service area distinction need to be recognized: urban and suburban, rural areas having small farms and mixed communities, and rural areas having large farms and scattered population.

Urban and Suburban

In most respects, all of the generic types of load control will benefit from the high density of controllable load which is characteristic of urban and suburban areas. These systems contain a proportion of the total equipment which is either common to all end use customers (such as the central control) or is common to specific geographical groups of customers (i.e. those fed from one injection station). Compact areas with the resulting higher load densities result in generally shorter transmission paths, less duplication of equipment, and a distribution of the costs of the common equipment over a much larger number of customers. High customer densities also have some detrimental effects on system performance which cannot be ignored. The significant influence of urban and suburban areas on the equipment are listed.

- a. Radio - High customer density permits many receivers to be installed within the transmitter service area; however, the service area may be reduced in size. This is due to the need to increase signal strengths to compensate for man-made noise (electrical appliances and motor vehicle ignition) and screening by certain types of building construction. High density areas may require a more complex control philosophy with the resulting increase in control command requirements.

- b. Power Line Carrier - The increase in the number of customers per mile of line is of benefit to all forms of power line carrier equipment in lowering the total line signal attenuation. Generally, these networks have lower impedance values which reduce the use of voltage correction capacitors and similar signal shunting devices. The use of customer power factor correction capacitors is likely to be high.

While the rhythmic coding is less subject to the higher line noise likely to be encountered, the multiple command requirements may prove to be a limitation in its use. Both low frequency multibit code and high frequency carrier have ample command capacity. High frequency, two-way systems are particularly well suited to dense areas due to the cost sharing possible and the interrogation capability in locations where physical access is inherently difficult.

- c. Hybrid Radio/Power Line Carrier - This exhibits the same characteristics as the radio system for the radio portion although the shared use of the voice communication base station may become less attractive due to the increase in general traffic brought about by a larger (capacity) system. The economics of the VHF receiver/retransmitter are enhanced by the characteristically large number of customers per transformer in urban areas.
- d. Telephonic and Direct Wire Systems - The benefits of urban areas over other than purely rural areas is considered to be marginal but by similar reasoning, there are no significant penalties either.

Small Farms and Mixed Communities

For the distribution system serving small farms and mixed communities in rural areas, a closer examination of the service area is necessary to characterize customer density. Typically, the type of service area of this type would be categorized by large housing lots, small communities, and a small average number of customers per distribution transformer.

Systems most suitable for this application are radio, high and low frequency power line carrier systems, and telephone.

The high frequency power line carrier suitability is based on the availability of a sufficient number of customers tied to a feeder or substation location. As the high frequency signal has a greater attenuation and a shorter range than the lower frequencies, the high frequency power line carrier system option is highly sensitive to the dispersion of loads on the system. The bi-directional feature of the high frequency power line carrier, if required, may offset a portion of the cost penalties to be recognized in serving this type of service area by more fully utilizing line or substation area equipment. Address capability not used for customer meter service due to there being too few customers within effective range may be occupied by substation and line metering functions, circuit breaker positions, and similar network status signals.

The use of low frequency power line carrier systems is suitable for this type of service area, but should be analyzed with regard to the number of commands required for load control. Systems operating on the simple rhythm code are likely to be preferable to multi-bit binary code type systems for a distribution utility requiring a small number of commands. Systems using the public telephone network would be suitable for this area application provided the capability exists for signal transmission over any telephone carrier links which may be present and provided the system could handle multiple end-use customers on a party line basis.

Large Farms and Scattered Population

In rural areas having a presence of large farms and a scattered population, the influence of a very low customer density is even more pronounced. Of the systems using power line carrier injection, only low frequency systems have a range suitable to cover a sufficient number of customers to be effective. The use of a telephone system may have advantages, particularly if coupled

with 2-way facilities. Caution should be exercised however, as a poor quality of telephone lines is common in this type of service area, as is the use of manual switching in telephone exchanges serving the smaller communities. Radio systems in some areas may suffer from economic penalties incurred from having relatively few customers within the range of any one transmitter.

Bulk Supply Arrangements

A second major factor to consider in the selection of the type of communication channel concerns the bulk supply arrangements of the distribution utility. The method of feeding a distribution utility may have a significant effect upon the choice of the communication medium. Exhibit VII-1 shows in basic terms the considerations involved. Radio, high frequency power line carrier, telephone, and the hybrid systems are immune from the effects of variation in bulk supply arrangements as they are connected into the system at the distribution voltage level.

Low frequency power line carrier systems are particularly sensitive to this issue. A distribution utility served via one bulk supply point may require only a single injection station to effectively cover the area. This may be the case also for multiple bulk supply stations if served from a common HV system. Should such a HV system be owned by the power supplier, agreement must be reached to permit the injection equipment to be installed on, and to inject the control signal into, the supplier system. The supplier must also agree to switching limitations to prevent interruption of the communication channel due to system switching.

If an area is fed from more than one wholesale supplier (or where one supplier provides power from non-common HV systems), then the low frequency system will suffer severe economic penalties. This is mainly because of the need for multiple injection points (one at each supply point). One additional penalty in the use of the low frequency system is the exposure to network modifications. Substation voltage changes or HV system reinforcement can fundamentally change the system injection requirements.

EXHIBIT VII-1

INFLUENCE OF BULK SUPPLY
ARRANGEMENTS ON THE COMMUNICATION PATH

Distribution System Characteristics

The third major aspect deals with those considerations which are engrained in the design and configuration of the distribution system.

Number of System Commands Required

For load control applications, the number of system commands is essentially a function of the number and types of controlled loads and the ability of the system to withstand the disconnection and reconnection of blocks of load. Differing types of controlled loads such as water heaters, space heaters, or air conditioners obviously are each subject to a control strategy unique to the load type and require separate commands. Within each of these groups, control may be further subdivided into discrete load blocks such that cold load pickup problems are averted by restoring some of the load diversity lost during the period of disconnection. As the number of these control blocks increases, greater and greater command capability is required from the load control systems.

If the estimated number of commands is in the order of 25 to 30, a comparatively simple signal code format will suffice typical of some radio and low frequency power line carrier systems. Ten times this number of commands will require somewhat more complex signal coding while commands exceeding these numbers will require the address capability available from the multibit binary codes used with the low and high frequency power line carrier. Telephone based systems and two-way high frequency power line carrier installations with the individual address capability are not as sensitive to the number of command requirements. They can fulfill the function for most applications of load control in addition to the principle function of interrogating and receiving replies from individually addressable locations. Cost justification for remote meter reading may be difficult at present for the distribution utility. In cases where a mandate may exist for time-of-day

metering, however, utilization of these systems offers an attractive method incorporating load control and other distribution system monitoring functions as auxiliary services which then become feasible at minimum additional cost.

It is important to evaluate the candidate communications systems command capability in view of future, as well as present, functional activities necessary. From a cost/benefit standpoint, the requirements for an economic payback should be weighed against the requirements for a reserve system capacity in the number of commands permitted in the design of the communication system.

Interrogation Limitations

With the two-way systems, the remote retransmitters can only initiate a signal upon interrogation by the control center, no spontaneous transmission is possible. Thus the usefulness is limited somewhat by the time slots available for routine scanning for information returns without seriously interfering with the system's primary function.

Proportion of Customers with Controllable Loads

The number of customers with controllable loads is an important consideration in the selection process. Should the total number of controlled customers be a small proportion of the total connected customers, radio or rhythm type low frequency power line carrier would be the better selections. These two systems have a large effective coverage area from a single signal transmission point and minimize the need for multiple shorter range equipment locations which may be under utilized due to the low controlled customer density. Telephone systems must be considered as a candidate for this application due to the high availability of telephones at customer locations.

The use of other systems would incur cost penalties such as:

- o Low frequency power line carrier using multibit codes would be under utilized due to the small number of commands needed.

- o High frequency power line carrier with its shorter effective range would be under utilized for load control unless the system was required for additional services.
- o Hybrid would not compete with radio systems because the small proportion of controlled customers would reduce the average number of controlled customers per transformer and influence the economics of the shared VHF receiver.

Customers Per Transformer Ratio

The ratio of controlled customers per transformer is significant to a possible application of the hybrid system. The design of the hybrid system includes a VHF receiver/retransmitter located on the distribution transformer low voltage circuit. The proportion of that receiver/retransmitter cost to be reflected in the cost per end-use control point depends on the number of controlled customers per transformer. Optimum application of the hybrid system suggests a controlled customer to transformer ratio of at least 3 to 1. The hybrid system maybe compatible with a VHF radio end-use receiver system. For some utilities with pockets of high customer density and areas of scattered population, it is possible to design a hybrid and radio combination system.

Line Electrical Noise

Line electrical noise is an important consideration for all except the telephone communications system. Locations containing significant welding or similar arc producing equipment subject the network to localized electrical noise or, in the case of major equipment such as electrode boilers or arc furnaces, to noise which is likely to be more widely distributed. While all systems can compensate for normal system noise, low frequency systems are more exposed to the effects. The multibit code low frequency power line carrier system is likely to be the most vulnerable to line electrical noise.

Performance of VHF Communications

Performance of the VHF communications in the service area is an important factor if hybrid or radio systems are considered. Most distribution utilities use mobile VHF two-way voice radio systems for day-to-day operations and the radio and hybrid system both use similar equipment. The hybrid system may use the existing VHF base station transmitter. Satisfactory operation of either system will be indicated by the operation experience gained from the voice channel. Unsatisfactory mobile operations may indicate potential signal strength problems for radio control, particularly if the local area contains hilly or mountainous terrain which may screen valleys from radio signals.

Physical Dimensions of the Area

The application of radio systems is affected by the physical dimensions of the area to be covered. As the length-to-width ratio of the area increases, radio systems tend to become more costly, particularly where one dimension is significantly less than the transmitter's service area. Such areas, together with areas of an irregular nature, can be covered with specially designed antenna systems.

Use of Multiple Load Control Systems

Adoption of one basic communication and control system to a given area does not automatically exclude the use of other systems on portions of the network. The control philosophy used between the system types is not fundamentally different. Such multiple system use may be necessary if isolated pockets are present that the base system cannot cover. Examples of such an application would be a small isolated portion of a distribution network fed from a separate bulk supply point or a well-shielded valley in a hybrid system. A second type system could be employed to cover the isolated area, either connected by land line to the central control or alternatively, keyed from a receiver fed by the base scheme.

If the use of combination systems can optimize the economic payback life, the incentive to explore this alternative is pronounced. At the same time, not all communication channels are compatible for signal transfers between systems. Two-way power line carrier systems, for example, cannot interact with one-way systems for message handling capabilities.

Distribution System Planning Considerations

A characterization of the existing distribution system and operating environment is not, in itself, sufficient information for selecting the type of system applicable. It is most important to review the plans of the utility that may effect the future usefulness of a load control system.

The distribution network is the communication path for the power line carrier systems. As such, any planned system reinforcement that might effect the sizing or location of injection equipment is integral to the investment requirements of those types of systems.

It is necessary to realize the effects of customer shifts that may occur over time in the service area. Inordinate load or customer shifts from one area to another may require - for power line carrier systems - the movement of injection facilities, or the consideration of a system with injection at a higher voltage level.

The effect of bulk supplier planning on distribution expectations is a determinate. The plans of the supplier should be reviewed to gauge the impact of that forecast on the distribution utility. System improvements, relocations, and modifications may effect the placement and sizing of injection equipment. Even so, there are always unforeseen events that will cause the wholesale supplier to change this year's 5-year plan next year.

Changes in the regulatory environment are even more difficult to predict. Rule changes, environment constraints, and new procedures are being proposed all the time. Trends may be useful in developing an idea towards change if only because the legislative mechanism works slowly. No assessment is offered in this report concerning regulation.

Changes in the rate structure could effect the selection of the type of control system. Plans to incorporate time-of-day rate structure, for instance, may change the choice of the system best suited for the overall application.

SECTION VIII

ECONOMIC EVALUATION METHODOLOGY

A. ONE WAY LOAD CONTROL SYSTEMS

For an individual utility, the merit of load control hinges upon a favorable balance of potential benefits over inherent costs. Further, the relative merit of alternative types of load control systems is a function of the relationship between their respective benefits and costs. Obviously, if all systems produce the same benefit for the same period of time, the least costly system (considering all elements of current and future cost) is the best economic choice, all other things being equal.

There are a number of economic measures of project merit. Among these, the following will be treated in this discussion:

1. Net Present Value
2. Internal (Economic) Rate of Return
3. Benefit/Cost Ratio
4. Payback Period

Each of the first three methods is dependent upon present worthing procedures. That is, they recognize the time value of money.

Net present value is established as the difference between the respective present worths of project benefits and costs, or conversely the present worth of annual differences between benefits and costs. Some analysts prefer the NPV method of project evaluation because it explicitly defines the magnitude of potential savings or other net benefit. This is particularly useful where project benefits vary appreciably between alternative programs. Since, in the instant case, the principal benefit of load control for a non-generating utility is considered to be the capacity cost savings in purchased power expense, direct load control

benefits are the same for any system capable of accomplishing the prerequisite load control. As a consequence, the Benefit/Cost Ratio method serves as a more direct indicator of economic feasibility.

The Internal Economic Rate of Return is defined as that discount rate which produces a net present value of zero, i.e. discounted costs and benefits are equal. An internal rate of return greater than the utility's cost of capital would generally be an indicator of project worthiness. From the non-generating utility's standpoint, this method suffers from the fact that for precise determination, a computer is almost essential since an iterative process is involved.

The Benefit/Cost Ratio on the other hand is a relatively easy test to make, and, particularly where benefits are generally static as between alternative load control systems, is a reliable measure of economic priority.

The suggested methodology which follows relates to the development of the Benefit/Cost Ratio. The Payback Period application will also be treated subsequently.

1. Benefit/Cost Ratio Methodology

It would appear obvious that if the benefits to be derived from a course of action exceed the costs of achieving those benefits, the undertaking is a worthy one, all other things being equal. The Benefit/Cost Ratio is an economic measure based on the ratio of Benefits to Costs; and in its strictest sense, a ratio better than unity is indicative of project worthiness.

On the other hand, relative B/C ratios are not necessarily a realistic criterion for evaluation between alternative projects. For a exaggerated, but legitimate example, an investment of \$100,000 to produce a \$200,000 benefit may very well be considered to have priority over a \$1,000 investment to achieve a \$3,000 benefit, even though the B/C ratio

of 3:1 in the latter case is greater than the 2:1 ratio produced by the former. The virtues of the Net Present Value approach may be seen from this application.

However, for the evaluation of load control systems, at least for one way systems, the compelling benefit for non-generating utilities is in every case the same - the potential reduction of capacity costs incurred in connection with power purchases. In this specific context, the B/C ratio therefore serves as a valid measure of the relative merit of alternative solutions.

In order to properly compare costs and benefits, they must, of course, be stated on a comparable basis. Load Control Systems represent a sizeable "up front" investment to provide benefits that will hopefully prevail throughout the lifetime of the apparatus installed. Consequently, equalization of timing differences is of primary importance in equating benefits and costs. The Levelized Annual Equivalent basis proposed in this application equalizes these factors.

a. Development of Levelized Annual Costs

- 1) Determine Alternative Investment Costs - The criteria for developing total load control system installed costs have been described in Chapter VI of this Report. As indicated, different components make up the alternative systems under review and variances in operating procedures produce differences in costs of installation and similar other factors as well.
- 2) Establish Fixed Charge Rate

To express load control system costs in terms of a single initial cost would, from the ratepayer's viewpoint be a misstatement of the fact. For an investor owned utility, that investment becomes a component of Rate Base on which an annual

minimum acceptable return is to be earned. The return provides the means to pay annual interest charges on incurred debt, to pay preferred stock dividends if applicable, and to provide a return on common equity at a level sufficient to make the utility's stock an attractive investment for potential new stockholders. These factors together constitute the Cost of Money component of the Fixed Charge Rate.

Before the annual return is realized, the utility may be subject to federal and perhaps state income taxes on the revenues generated to produce such return, and the investment itself must be recovered over the life of the equipment.

For a non-profit municipal or cooperative electric system, the debt vehicle is generally either Municipal Bonds or REA type loans. Since, generally, no stockholder costs are involved, the cost of money relates solely to debt service, and, of course, income taxes are not incurred.

In addition to the above annual costs, property taxes may be assessed by local authorities. Insurance or other similar costs may be considered desirable. All of these factors may be most conveniently expressed in a Fixed Charge Rate which when applied to the total investment yields the levelized annual system costs exclusive of operation and maintenance expenses. The Fixed Charge Rate then consists of:

- Cost of Capital
- Depreciation
- Income Taxes
- Property Taxes
- Property Insurance if applicable
- Other Annual Costs if applicable

The Cost of Capital is simply the annual interest rate for current debt vehicles, or, for stock companies, the weighted

average current cost of all components of capitalization in a desired mix. In the Case Studies in Appendix A, 7% was used as the prevalent interest rate for municipal bonds and 5% in connection with REA type financing. For the investor owned illustration, the composite cost of capital was developed in the following manner reflecting 1974 cost levels:

	<u>Percent of Total</u>	<u>Yield</u>	<u>Weighted Cost</u>
Long Term Debt	52%	9.65%	5.02%
Preferred Stock	10	11.20	1.12
Common Equity	38	11.73	<u>4.46</u>
Composite Cost of Capital			<u>10.60%</u>

The Cost of Capital thus established may generally be assumed as the minimum acceptable rate of return and consequently, the discount rate to be used in all present worth determinations.

In the context of a Fixed Charge Rate, depreciation is expressed as the annual Sinking Fund factor which when applied to investment cost yields the levelized annual deposit which at a compound interest rate equivalent to the cost of capital will produce an amount equal to the original investment over the service life assumed for the load control system. For even discount rates, this factor may generally be found in compound interest tables. In the case of less common discount rates, the factor may be determined from the following formula:

$$\text{Depreciation Factor} = \frac{i}{(1+i)^n - 1}, \text{ where } i = \text{interest (discount) rate} \\ \text{and } n = \text{average service life}$$

Together, the Cost of Capital and the Depreciation Factor constitute the Capital Recovery Factor.

Generally, property taxes, property insurance, etc. are already levelized in that they represent fixed annual amounts which may be expressed as a percent of investment. Consequently, this established percentage relationship may be directly incorporated into the Fixed Charge Rate. Where variation in future levels may be reasonably anticipated, annual charges over the life assumed must be present worthed to current levels and converted to annual equivalents by means of an annuity factor.

Where it applies, Income Tax is the most complex component of the Fixed Charge Rate. Treatment varies by tax source and because of specific options adopted in individual applications. In keeping with the other components of the Fixed Charge Rate, income taxes are expressed as the annual equivalent of the present worth of income tax obligations over the life of the investment. A somewhat simplified development of the income tax component is included in Case #1 of the Appendix A of this Report. Particularly, because of this complexity, many companies employ a computer program to develop annual fixed charges and a levelized fixed charge rate.

- 3) Apply Fixed Charge Rate to Investment Costs - Since the Fixed Charge Rate has been established on a levelized basis, the annual equivalent fixed investment costs for comparative purposes result directly from application of this Rate to Installed Costs as previously determined.
- 4) Determine Levelized Annual Equivalent Operation & Maintenance Expenses

In addition, annual operation and maintenance expenses associated with the various systems must be recognized in the total cost stream. The basis for the estimation of O&M expenses has been previously detailed in Section VI and specific applications are developed in the illustrative case studies.

In connection with the economic analysis, it is appropriate to recognize future escalation of O&M expenses as developed at present cost levels. (In the Case Studies, an annual escalation factor of 7% has been uniformly applied. Of course, this factor would vary in accordance with specific circumstances). Finally, levelized annual operation and maintenance expenses are represented as the annual equivalent of the present worth of escalated expenses over the life of the investment.

For illustrative purposes, consider this example of constructing levelized annual O&M expenses for one of the generic system types analyzed in the winter-peaking urban utility casework:

	<u>Year</u>	<u>O&M Expense</u>	<u>Present Worth Factor</u>	<u>Amount</u>
O&M Expenses As Developed	1	\$15,354	.917431	\$14,086
Anticipated Expense at 7%				
Annual Escalation	2	16,429	.841680	13,825
	3	17,579	.772183	13,574
	4	18,810	.708425	13,325
	5	20,127	.649931	13,081
	6	21,535	.596267	12,841
	7	23,043	.547034	12,605
	8	24,656	.501866	12,374
	9	26,382	.460428	12,147
	10	28,229	.422411	11,924
	11	30,204	.387533	11,705
	12	32,319	.355535	11,491
	13	34,581	.326179	11,280
	14	37,002	.299246	11,073
	15	39,592	.274538	10,870
Total				\$186,204
Annual Annuity Factor				.124059
Annual Equivalent				<u>\$23,100</u>

In this illustration, a discount rate of 9% was assumed. For even, or other commonly used discount rates, both present worth and annuity factors may be determined directly from compound interest tables. In other cases, the following formulae may be applied:

$$\text{Present Worth Factor} = \frac{1}{(1+i)^n}, \text{ where } i = \text{discount rate} \\ n = \text{year}$$

and:

$$\text{Annuity Factor} = \frac{i}{1-V^n}, \text{ where } i = \text{discount rate} \\ V^n = \text{present worth factor in final year.}$$

- 5) Summarize Levelized Annual Costs - Total costs, for analysis purposes, are the summation of levelized annual fixed costs and operating expenses associated with load control systems.

b. Development of Levelized Annual Benefits

For a non-generating utility, the overwhelming benefit, if any, represented by load control is the potential savings in the capacity cost component of purchased power expense. This is not to imply that other benefits may not accrue, but it would appear that basic justification must reside with this factor. Consequently, this illustrative Benefit/Cost Methodology is predicated on this single potential benefit.

- 1) Determine Potential Current Capacity Cost Savings - Having defined appliances to be controlled, the potential diversified demand thereby subject to control and a load control strategy to achieve maximum cost advantage, total controlled load in each month of the year may be determined.

In order to translate the respective control levels into potential capacity charge savings, present or prospective bills for electricity are calculated on a month by month basis both

before and after adjustment of billing demands to reflect load control. To the extent that carryover ratchets are imposed, the full impact of load control may be somewhat restricted until the second year of operation, and seasonal demand fluctuations may impose ratchet limitations even thereafter.

Annual net savings representing the difference in calculated billings with and without load control should be reflected for each year throughout the projected life of the load control hardware. Since it appears reasonable to assume that bulk power billing rates will undergo continuing upward adjustments, it is likely that annual net savings will escalate over the forecasted period.

In the Case Studies developed in Appendix A, an estimated annual escalation factor of 7% has been uniformly applied.

2. Convert Potential Future Savings to Levelized Annual Equivalents -
Once again, in order to express all terms on a comparable basis, future capacity cost savings are converted to levelized annual equivalent amounts through the application of present worthing techniques.

The capacity cost saving in each future year is reduced to its present worth under the discount rate applicable. The cumulative present worth of savings in all years is converted to a levelized annual equivalent amount by means of the annuity factor previously defined.

- c. Summarizing Costs and Benefits for Comparative Analysis

Comparative costs and benefits are conventionally measured in terms of a Benefit/Cost Ratio. Since the ratio is developed by dividing project benefits by project costs (expressed throughout this

procedure in terms of annual equivalents) a ratio in excess of unity is indicative of a favorable evaluation status, all other things being equal.

A flow diagram tracing each step of the Benefit/Cost Ratio methodology is included as Exhibit VIII-1.

2. Payback Periods

As a further measure of project acceptability, individual payback periods may readily be determined. The Payback Period is defined as the number of years required to recover original investment from net returns before depreciation but after taxes (if applicable).

In the illustrative cases provided in the Case Studies in Appendix A of this Report, annual net returns have been developed as the net annual savings in capacity costs after deducting O&M expenses and property taxes. In the case developed for the privately-owned utility, cumulative net savings are reflected both before and after income taxes for comparative purposes only.

By definition, the payback period is established in that year when cumulative net savings equal or exceed the original installed cost of the system under analysis. It should be noted that in the sample cases developed, an escalation factor of 7% has been uniformly applied in projecting both annual savings and O&M expenses. Consequently, payback periods indicated are subject to this factor. A greater or lesser payback period would obviously result if alternative escalation bases were to be considered appropriate.

3. Sensitivity Analyses

Inevitably, some assumptions must be made in the course of economic analysis. Although based on the best available information, they may, if in error, bias an investment decision. In order to measure the impact of

EXHIBIT VIII-1
BENEFIT/COST ANALYSIS FLOW DIAGRAM

certain pivotal estimates or assumptions, the analysis results should be redefined in terms of alternate determinants.

In the Case Studies, project benefits and costs have been uniformly developed on the basis of a 100% acceptance rate; that is, agreement by all customers with potentially controllable loads to accept load control. Obviously, this may very well overstate the actual circumstance.

In order to measure the impact of varying acceptance rates, control system costs are segregated into fixed and variable components. The fixed component covers certain central system costs which are inherent in the system and therefore apply at all acceptance levels. On the other hand, certain other costs are directly proportional to the number of installations, and the total cost at any acceptance level is a combination of the fixed cost and the cumulative variable costs for that number of installations. Since capacity cost savings vary directly with the amount of controlled load, benefits are linear from zero to that level established at the 100% acceptance rate. In combination, relative costs and benefits may be determined at any acceptance rate, and critical acceptance levels may be defined.

As a further test of sensitivity, estimated project costs may be adjusted either upward or downward by a fixed percentage. The effect of escalation may be readily determined by restating the analysis without consideration of inflation, particularly that reflected in future capacity cost savings.

B. TWO WAY SYSTEMS AND THE EVALUATION OF ANCILLARY FUNCTIONS

1. Two Way Control Systems

Previous discussion has been devoted exclusively to load control and that in the context of one way systems. It is inappropriate to compare one and two way systems without consideration of the additional benefits potentially afforded by a two way control and communication device. State of the art development of two way systems presently provides capability with respect to at least the following functions in addition to direct load control:

- Remote Meter Reading
- Time-of-Day or Other Time Differentiated Metering
- Load Survey Capability

In addition to these customer related functions, the two way communication links provided by systems of this type lend themselves to other system related functions such as:

- System Monitoring
- Dynamic Distribution Automation
- Fault Location
- Optimized Voltage and VAR Control
- Capacitor Bank Switching

Although these latter functions add an additional perspective in management's evaluation of alternative load control devices, such utilization is somewhat far afield from the direct emphasis of this analysis. It is appropriate, however, to consider potential future uses of a two way control system when making such an evaluation even if only in an intangible manner. Such system applications would permit a sharing of central facility costs which, particularly for a two way system, impose a significant burden when measured only in terms of load control.

For those customer related functions initially indicated, a prerequisite management decision or regulatory mandate would probably serve as the impetus to embark on any or all of the designated programs. The attractiveness of a two way system is obviously enhanced by, for example, an actual or anticipated decision or order to adopt time-of-day rates, thus necessitating a multi-part metering capability. Obviously, if that requirement can be accomplished in conjunction with a system which also provides a means for direct load control, a potential mutual advantage exists.

2. Benefit of Ancillary Functions

A Benefit Cost analysis for a two way system would necessarily include consideration of any of those additional functions presently necessitated or realistically anticipated. Two way load control systems frequently have the capacity not only to read meters remotely, but to do so in a time structured mode separately identifying consumption in pre-designated peak, intermediate and off-peak periods. This capability permits the implementation of time differentiated rates, and the benefits could therefore be equated to the load management benefits attributable to time-of-day or other time structured rates.

However, in the absence of full scale implementation or a comprehensive test, the degree of price elasticity and therefore the load management impact of peak or related pricing is generally unknown. Given, however, a management decision or other mandate to implement time structured rates, the ancillary benefit accruing to a two way system is equal, at least, to the cost of otherwise accomplishing multi-part metering.

Similarly, for each function indicated and for any other function envisioned, an alternate means of accomplishment probably exists. Meters are presently being read on a regular basis by Meter Readers. Two or three dial conventional meters are on the market and would serve as a basis for evaluating time differential metering capability. Cassette type load survey meters provide a means to measure on-site customer loads on a continuous basis.

The least cost alternative means of accomplishing the same function may reasonably be assumed as the benefit of a two way communication system insofar as that function is concerned. Care must be taken, however, to consider all costs of alternative means. Although no such direct development of costs is made in this Report, the following listing indicates the nature of items to be considered in measuring typical alternative costs for each of the ancillary functions indicated above:

Conventional Meter Reading Costs

Personnel Costs

- Meter Reader wages
- Supervisory salaries
- Fringes and Benefits
- Overhead costs

Transportation Costs

- Use of company vehicles
- Reimbursement for use of personal vehicles
- Per diem allowances

Miscellaneous Costs

- Office space and supplies
- Postcards and forms for "not at homes"
- Property damage and other liability insurance
- Postage
- Personal injury costs

Other Labor Related Functions

- Special field readings
- Off/on readings at customer's request
- Billing costs for incorrect reads
- Personnel time devoted to answering complaints and inquiries occasioned by estimated bills.

Time Differentiated Metering (Conventional)

Two or three dial meter costs¹
 Operation and maintenance expense
 Incremental meter reading costs

Load Survey Capability

Conventional load survey meter costs
 Spare cassettes
 Personnel costs for tape changeout
 Transportation costs for tape changeout
 Maintenance costs

In each case, benefits based on recognition of the above alternative costs would be in addition to that attributed to the two way system's direct load control capability.

3. Evaluation of Ancillary Functions

As with the load control evaluation, any analysis related to combined functions should be developed on annual equivalent of present worth basis in order to account for differences in service lives, escalation factors or other variances. To compare non-uniform series of money disbursements where money has a time value, it is necessary somehow to make them comparable. Expressing each in terms of annual equivalent costs is one way to accomplish this purpose.

Certain of the ancillary functions indicated above may also be accomplished as extensions of the capability of at least some of the one way load control systems. For example, capacitor switching could be handled with radio control as could certain other Distribution Automation functions. Furthermore, caution should be exercised in the process of applying two-way high frequency power line carrier systems, to distribution control and surveillance functions. The use of the frequently coined term "distribution automation" has led to the common interpretation that

two-way systems of this type are equivalent to or may be used for purposes similar to Supervisory Control and Data Acquisition Systems as they are presently available. In developing cost benefit figures, care must be exercised to define the actual practical use of power line carrier facilities and to differentiate between this and the generally accepted use of the term SCADA equipment.

The basic difference in the two types of equipment is one of intelligence brought about by the achievable transmission speed of the available communication channel. This ranges from slow, as used for the power line carrier (30 bits per second) to relatively fast for SCADA systems utilizing leased telephone lines or microwave channels. Due to the requirements of message protocol, it is usual that such data gathering systems are designed to respond on demand only-such that remote data acquisition device with a message to send must await an interrogation command from central control. It is then apparent that the time resolution of data gathered is strictly a function of communication channel bandwidth (transmission speed), and the number of points scanned. These two factors control scanning speed or in other words, the number of interrogations of a single point in unit time.

If it is accepted that the principal purpose of the two-way power line carrier is to control customer appliances and remotely read billing meters, then it must be apparent that its use for any purpose other than elementary system monitoring will either severely restrict the primary purpose or, alternatively result in extremely slow scanning speeds for interrogation. Time is not available for any other conclusion with the average message times. This in effect limits the usefulness of distribution automation functions to such slow speed actions as tap change control (possibly for system brownouts), capacitor switching, loss of voltage detection (fault identification) and other similar non-repetitive functions. Repetitive functions such as substation metering, switching, alarms and similar data collection which, to be useful, requires rapid and constant updating for presentation as a system mimic diagram is more properly the prerogative of the high speed, wide bandwidth data channels.

Quantified benefits may be developed as the composite of:

- a. Either the annual equivalent present cost of accomplishing the function or the levelized fixed charges related to the least cost alternative method for accomplishing the same function, and
- b. The levelized annual equivalent operating expenses associated with alternate hardware or means.

For evaluation purposes, the individual benefits of the multiple functions of a two way system would be directly additive if developed on an annual equivalent basis. From a cost standpoint, care must be taken to include any optional costs associated with the implementation of ancillary functions. With respect to the basic load control function, the annual equivalent benefit should be based not on potential future capacity cost savings but on the least cost alternative means of accomplishing load control as determined from application of the Benefit/Cost methodology previously discussed. This concept is incorporated in the ancillary function evaluation procedure diagrammed in Exhibit VIII-2.

Customer Incentives

On an economic break-even basis, the maximum dollar incentive than can be provided to the customer can be derived given the annual equivalent costs and benefits for each generic type of communications and control equipment and specific control strategies. For a given level of customer participation, and dividing by 12 for conversion to a monthly time frame, the customer incentive becomes:

$$CI_1 = \frac{(B_1 - C_1)}{12N_1}$$

where: CI_1 = Monthly customer incentive
 C_1 = Annual equivalent cost for generic type 1 at N_1
 B_1 = Annual equivalent benefits for generic type ~~1~~ at N_1
 N_1 = Participation level of customers at CI_1 ,

EXHIBIT VIII-2

2-WAY LOAD CONTROL SYSTEM -
ANCILLARY FUNCTION EVALUATION

NOTES:

- (1) In decision process above, a probability can be assigned to an ancillary function being required, if it is considered possible (probability x cost). Otherwise, it should be considered a probability of zero for being required.
- (2) The benefits should be quantified as those accrued from having that ancillary function, and not any comparison with the cost of other equipment, etc. to perform that function.

Note that because of the interrelationships of these parameters, no independent variable exists. Comprehensive customer surveys are thus necessary to identify to what extent customer participation is affected by perceived benefits and/or incentives. In a more general sense, a load control program is viable if the incentive (both long term and short term) required by the average participating customer is less than or equal to the possible customer incentive for the number of customers participating (the possible incentive level is provided in the above equation).

In this regard, all benefits should be viewed from the perspective of the customer. This assures that a valid cost/benefit analysis is conducted in examining the feasibility of load control. If communication of all costs and benefits is adequate, the average customer's decision is an economic one, even if implicit. Therefore, if benefits are diluted by not specifically identifying savings returned to the customer as being derived through load management, or by distributing them to all customers rather than participating customers, a distortion of this economic decision is created, confusing a clear evaluation of the program.

To illustrate how the customer incentive variables interrelate, consider the following:

If the fixed costs of a load control system are relatively high in relation to the variable costs and the number of customers participating is relatively low, then the cost per customer will obviously be high. If the net benefits per customer (savings less load control program costs per customer) controlled are not significant enough, the possible customer incentive may not be sufficient to be acceptable to the average customer over a long period. Furthermore, if the subsequent customer participation is too low, net benefits cannot be sustained. Finally, if benefits do not remain clearly greater than costs, the program will obviously be infeasible. As noted above, the threshold incentive level at which customers will reject a specific load control program as not worth the interruption of certain appliances, can only be ascertained by a comprehensive survey over several years. Ideally, this should be performed in conjunction with a pilot load control program.

FOOTNOTES

1. Alternative multi-part metering for polyphase installations would probably have to be accomplished with recording meters. In this case, the annual benefit of the two way system's time structured metering capability is equivalent to the annual fixed charges related to meters of this type, including the necessary pulse initiators, spare cassettes, miscellaneous materials and installation cost thereof, plus the annual equivalent operation and maintenance expense and incremental meter reading expense associated with conventional metering.

SECTION IX

THE IMPACT OF WHOLESALE RATE STRUCTURE ON LOAD CONTROL

There is considerable industry agreement that the most important benefit of load control is the savings accrued to the non-generating utility through a reduction in demand, hence, the costs of wholesale power purchases. The amount of savings that can be realized will depend, among other things, on the magnitude of the reduced load and on the demand charges built into the wholesale power rate structure, which are subject to periodic changes. Therefore, to evaluate and assess the savings that may be expected from load control programs, it is important to understand the various factors that may affect the wholesale power rate to the non-generating utility. These factors include: (1) the method by which the revenue requirement of the wholesale power supplier is established; (2) the billing determinants used to recover that revenue level; (3) the structure of the rate itself regarding capacity costs and energy costs; (4) the number, size and diversity of non-generating utilities served under that wholesale rate; (5) the timing of wholesale power rate increases relative to the initiation of the load control program; (6) the regulatory jurisdiction under which the load control program's wholesale power rate is established, if any; and (7) the general nature of the relationship between the power supplier and the non-generating utility.

1. Revenue Requirements

Revenue requirements, defined as the cost of providing service at a given voltage level, should be the same for power supplied to a distribution system whether or not that system is owned by the supplying utility. In other words, for a given utility, the "wholesale" rate charged for service provided to another non-generating utility for resale should be equivalent to the power supply costs incorporated in the supplying utility's rates for its own distribution level customers.

To obtain the pro rata share or proper amount of fixed charges associated with power supply, the causal relationship of power supply and costs must be examined. If, as a result of certain peak demands or reliability criteria, increased production and/or transmission costs are incurred by a generation utility, these casual factors should be considered so that incremental costs are allocated to those customers responsible.

Frequently, however, the method actually used to establish the revenue requirements for a wholesale power rate is not totally consistent with the cost factors of the supplying utility. Be this as it may, if the wholesale rate is "cost-based", there should be some combination of demands to other allocation factors which are used to set the level of annual revenue requirements from wholesale rates. The factors which determine this overall allocation to wholesale service must be considered in the load control strategy of the non-generating utility.

Load control may not affect the capacity related revenue requirements of the supplying utility. However, such control will result in a reduction of overall revenue derived from the wholesale of electricity and may prompt the supplier to adjust the wholesale rate in order to recover its sunk cost. In such case, the adjustment of wholesale power rate may affect the amount of savings that a non-generating utility can expect from the load control program.

If the rate adjustment is universally applied to all wholesale customers, a possible effect of load control programs is to shift a portion of the supplying utility's costs to its other customers not implementing load control. Here, one's perspective is important. If the non-generating utility's relative share of the supplying utility's total cost is small, certain constraints affecting revenue requirements such as timing, plant size and location, reliability, and other planning criteria may override the effect that the non-generating utility's load control program might otherwise have on planning and total costs. In such cases, wholesale power costs to the non-generating utility may remain unaffected, and the long-term savings from load control program can be realized.

2. Billing Determinants

Normally, after revenue requirements have been determined, the next consideration is revenue recovery using a rate form geared to selected billing determinants. For the non-generating wholesale customer, these determinants are commonly in one of the following forms: monthly maximum demands at individual metering points, the coincident monthly maximum demands of all metering points of the non-generating utility, or even some combination of demands coincident with the supplying utility's peak demands. In addition, a ratchet form may be introduced to establish a minimum monthly demand at some percentage of the highest billing demand established in previous months. This ratchet may be even as high as 100%. The interval of recorded demand, whether 15, 30, or 60 minutes, has little effect on load control strategies currently in use.

3. Demand Charges and Billing Determinants

Quite often in the structure of wholesale power rates, some portion of the total capacity costs are designed to be recovered in the energy charge. The greater the amount of capacity costs that are included in the capacity charge portion of the rate, the higher the \$/Kw and the greater is the savings that may be obtained from each Kw controlled. In any case, that portion of total revenue requirements to be recovered through demand charges is divided by total demand billing determinants to establish the unit price per Kw of demand. As discussed above, using load control to reduce the billing demands after the rate is established, will, of course, reduce the monthly wholesale power bill. If, as a result of load control, total class demands are less than the billing determinants used to establish unit price, a shortfall will result in meeting the supplying utility's revenue requirements. Consequently, although short term savings may accrue to the non-generating utility implementing load control, such savings may be jeopardized in the next rate filing when per Kw capacity costs are adjusted upward to reflect the

decrease in billing determinants. This would generally be the case unless the impact of load control is insignificant with regards to a proportional reduction in the overall wholesale class revenue requirement.

If the non-generating utility with load control is identified as a single wholesale power customer with an individual wholesale power rate the situation indicated above will be even more pronounced. If load control strategy focuses only upon a reduction in billing units, and the demands and other factors impacting periodic determination of revenue requirements are not affected, savings will only result until the time when that individual rate is again brought under review, all other considerations remaining unchanged. With the revenue requirement unaffected and only the billing units reduced through load control, the per unit capacity charge will be increased and any further savings will be eliminated. A simplified comparison of the impact of wholesale rate on the long term and short term benefits of load control is provided in Exhibit IX-1.

4. Impact of Ratchet Provision

There are additional considerations regarding load control and billing demands. It may be assumed that in order to realize maximum savings when a ratchet is not in effect, demands in all months would have to be controlled (assuming potentially controllable loads exist in each month). However, when a ratchet provision is in effect, control might not be necessary in those months having an otherwise lower billing demand than the minimum billing demand based on the ratchet provision and established even after control is accomplished in peak month(s). Often the ratchet provision is seasonal, and the effect can only be determined after evaluating the specific rate.

5. Metering Points, System Peak, and Distribution Peak

To produce savings through control of specific demands requires that some means be available for anticipating when those demands would reach a "critical" level. This level would be set such that control might produce a savings. Total system load of the non-generating utility is generally, but not always, monitored; control decisions may have to be based on the coincident load of all metering points. In some cases the wholesale rate may be billed on individual metering points, or there may be other reasons for attempting to control on an individual substation basis such as savings in distribution investment. If a control strategy dictates that the individual peaks on all metering points or substations are to be reduced, the problems connected with predicting and controlling loads are multiplied. When maximum or long term savings from a wholesale power rate can only be achieved by controlling demand at the time of the supplying utility's peak, additional metering and cooperation between supplier and non-generating utility may be necessary.

6. Frequency and Timing of Rate Adjustments

As indicated previously, savings may be considerably reduced or even eliminated after a wholesale power rate is restructured. However, with relatively short payback periods, the non-generating utility may recover at least the majority of all load control system costs before the wholesale power rate is again reviewed and restructured. The timing of rate increases or rate reviews is therefore important in the short term perspective of the non-generating utility. Nation-wide, the frequency of rate filings and rate reviews has been increasing in recent years, and it is not uncommon to see wholesale power rate increases filed to the Federal Energy Regulatory Commission (FERC) every few years.

7. Summary

Many of the considerations discussed above would vary significantly from utility to utility, depending on the regulatory jurisdiction and organizational structure of the supplier and the non-generating utility. In recent years, the FERC has provided the following direction: required extensive cost support for wholesale rate provisions, emphasized coincident demands as the basis to set revenue requirements, allowed moderate ratchets provisions, and endorsed capacity costs with uniform capacity charges. Although there has been expressed interest in time-based rates and peak load pricing, the FERC has made no definitive commitments to these rate forms at the time of this Report.

The generating and transmission cooperative (G&T) and its member cooperatives represent a similar situation in some respects, but there are usually fewer well-defined guidelines for the wholesale power rate structure than under the FERC. Non-generating members of the G&T may also elect to conduct direct load control independent of G&T. While some of the G&T's power requirements may be purchased, a substantial amount of fixed costs associated with the G&T's own power supply may provide additional incentive for each of the non-generating utilities to coordinate their load control programs through the G&T.

EXHIBIT IX-1

IMPACT OF WHOLESALE POWER RATES ON LOAD CONTROL BENEFITS

	Without Load Control	Load Control by Non-generating Utility			
		Short-Term	Long Term Cases*		
			I	II	III
Revenue Requirements	\$100,000	\$100,000	\$100,000	\$100,000	\$100,000
Annual Billing Demands					
a. Non-generating Utility	4,000Kw	3,600Kw	3,600Kw	3,600Kw	3,600Kw
b. All other customers	36,000Kw	36,000Kw	36,000Kw	36,000Kw	36,000Kw
Capacity-Related Rates					
a. Non-generating Utility	\$2.50/Kw	\$2.50/Kw	\$2.50/Kw	\$2.78/Kw	\$2.53/Kw
b. All other customers	\$2.50/Kw	\$2.50/Kw	\$2.50/Kw	\$2.50/Kw	\$2.53/Kw
Annual Demand Charges					
a. Non-generating Utility	\$10,000	\$9,000	\$9,000	\$10,008	\$9,108
b. All other customers	\$90,000	\$90,000	\$90,000	\$90,000	\$91,080
Annual Savings:					
Non-generating Utility	-	\$1,000	\$1,000	0	\$892

Source: Hypothetical Data

Case I: Supplying utility does not consider the revenue loss of \$1,000 significant and does not file for rate increase. Results: Long term effect equals short term effect.

Case II: Supplying utility seeks to recover the \$1,000 revenue loss from the wholesale customers, possibly because the load control may not have affected the method used to establish annual revenue requirements for the non-generating utility from the supplier. If the non-generating utility is the only customer in that class, it will bear the entire burden.

Case III: Supplying utility seeks to recover the \$1,000 revenue loss from all of its customers and file a general rate increase. In such case, the burden of higher rate is to be shared by all customers.

SECTION X
SUMMARY - A PROCEDURAL OUTLINE

This section will serve two purposes. It will first summarize the main points of the report and offer insight where clear optimum choices exist. But secondly, and perhaps more important, this section provides a procedural outline for a non-generation utility to follow in developing a load control program. Because of the many combinations of user objectives and physical systems possible, the outline cannot be comprehensive enough to serve as a complete reference. It can, however, provide direction and outline the relationship of the necessary basic steps. This is the intent of the following pages of this section.

In its simplest form the evaluation and the feasibility of introducing a load control system into a non-generating utility consists of four major steps:

- I. Evaluate the existing (and potential) physical system
- II. Identify benefits of load control
- III. Identify costs of load control
- IV. Select operational system

The last step can be the easiest or hardest depending on the degree of success achieved in the research involved in steps I, II and III. These steps require a conscientious fact gathering and selection effort. A key determinant in evaluating the benefits (Step II) may be the ability to forecast future needs.

In the following pages these four major steps are expanded into a procedural outline with references to applicable sections of the report as necessary.

I. SYSTEM EVALUATION

A. Identify the Objective and Scope of a Direct Load Control System for a Non-Generating Utility

1. Develop reason(s) for load control - This will expedite decisions on communication system selection, load control strategy, level of control and economic evaluation. Essential reasons include: a) minimize bulk power demand charges via peak shaving, b) meet the electrical needs of a growing population with fixed capacity available, c) increase distribution system reliability, including emergency load shedding, d) meet the regulations mandated by public utility commissions or large public power pools (if a member).
(Section I)
2. Establish the scope of load control - Decide whether control should be 1 way or 2 way. (For example, if the objective is unquestionably limited to peak shaving, 1 way should probably be selected). Ancilliary benefits will influence this decision. Decide what level of end users will be controlled (residential, commercial, industrial). Note that these decisions will be preliminary pending investigations in load control strategy and economic analysis. A reiterative process is necessary.
3. Develop ancilliary benefits desired - Evaluate which ancilliary benefits can be obtained from current hardware and which benefits would dictate another hardware system. Determine the priority. A partial list of ancilliary benefits include:
 - a. automatic meter reading.
 - b. T.O.D. rates.
 - c. load research surveys and demand studies.

- d. distribution automation (switch control, fault location and isolation, feeder redeployment, capacitor switching, voltage regulator switching, feeder monitoring).
- e. street light control. (Section I)

4. Identify limitations on the effectiveness of load control

- a. Purchase power agreements - Terms and conditions of the tariff should be analyzed as well as any demand/energy provisions which may effect the control strategy.
- b. Organization - The non-generating utility may be associated with a larger utility group or public power pool which could establish priorities limiting the short term optimum load control for the non-generating utility.
- c. External - Regulation may impose some policies regarding load control, time of day rates, etc., relating to the end users or communications system.
- d. Technical - Conduct a preliminary review to recognize any communication hardware limitations. (Section VI)
- e. Physical - Conduct a preliminary review to recognize any limitations imposed by the distribution system.

B. Evaluate Existing Load Curves

System and/or subsystem load profiles and load duration curves are valuable aids in examining the existing load patterns as well as quantifying the effects of direct load control. The objective for load control will define which load curves are of interest. Specifically, when minimizing power supply costs, the nature of the

purchased power agreements will indicate the load curves which relate to the power costs. Where billings are set on coincident peak demands, the system profile is used. If non-coincident delivery point peaks set billings, a profile is needed from each point. In either case an hourly profile is required for the duration of the peak period. The profile is in turn used to develop the control strategy. (Section IV)

C. Evaluate Controllable Loads

The quantification of controllable load is directly related to the determination of benefits in the economic analysis. In order to estimate the amount of controllable load several factors need to be developed.

1. After establishing objectives for load control (paragraph IA1 above) and examining the appropriate load curves (paragraph IB above), the number and timing of control periods can be determined.
2. Controllable appliances need to be estimated for these control periods by: (Section II)
 - a. Appliance saturation survey.
 - b. Existing customer records, such as special rates or service connection application forms.
 - c. Billing records where high users may be assumed to have certain appliances.
3. Develop the controllable load per appliance for each control period from appliance diversified demand curves:
 - a. From "in house" load research data.
 - b. Published data of other utilities. (Section III-2)

4. Appliances returned to service after a control period require additional (payback) energy which must be accounted for in the control strategy. Develop energy payback curves for controlled appliances to model the load restoration demand in the control strategy.
 - a. From "in house" load research data
 - b. Published data of other utilities (Section III-2)
5. Determine loss factors to reference controllable load from the customer level to the delivery point.
6. Estimate a switch success rate to account for receiver switch and other equipment malfunctions.

In light of these factors, the following relationship can be used to calculate the controllable load at any control period.

$$C = \frac{ND(1-F)}{(1-L)}$$

Where: C = controllable load
 N = number of controlled appliances
 D = diversified demand per controlled appliance
 at the time of the control period
 F = switch success rate
 L = loss factor

D. Evaluate Physical Transmission and Distribution System

1. Identify the physical characteristics of the service area
 -Certain characteristics of a utility service area will exert strong influences on the choice of a load control system. Geographical location will control climatic conditions and be indicative of land topography. The former will affect the possible number of control commands required due to the type of load controlled and control program while mountainous terrain will detract from the effectiveness of radio coverage.
 (Section VII)

The dimensions of the area and its overall shape will be reflected in the total line route miles to be considered (affecting attenuation for carrier systems) and will generally be related to customer density. This latter consideration is important in determining the proportion of fixed common equipment costs to be allocated to each customer. This density factor is further influenced by the proportion of the total customers with controllable load. (Section VII)

2. Identify the electrical characteristics of the system - Under this category fall the methods of system construction (overhead vs. underground), interconnection and method of supply. Of equal importance to the knowledge of the existing system is an understanding of system reinforcements or extensions which are anticipated to occur within the expected life of the control system.

While the above will determine such features as line attenuation to carrier signals and the normal/abnormal location of a customer feed within the electrical system, the bulk supply arrangement is of primary importance. This factor alone may be responsible for the exclusion of several communication systems from consideration. (Section VII)

In the application of any form of load control communication equipment, whether one way or two way, it is desirable to examine the distribution system for other control functions ancilliary to the load control which may be incorporated economically into the scheme. These may be functions already provided by preset controls such as clock controlled capacitor switching or operations desirable but not yet available. (Section VII)

3. Examine demand conditions during load restorations - One concern in the widespread remote control of customers load is the destruction of the natural diversity during load restoration periods. A simulation of typical distribution systems to determine localized overload and volt drop conditions during load restoration periods shows that for normally designed modern networks no such overloading of distribution apparatus is to be expected. This modelling technique utilized control strategy requiring load restoration in somewhat larger blocks than would be met with in practice. Areas involving older networks which have not been reinforced over the years to keep pace with the expanding use of electric appliances should however be suspect and examined in more detail. (Section V)

E. Evaluate Feasible Control Systems

Although many differing control systems are available for the remote direct control of customer's loads, these may, in broad terms, be broken down into five basic generic groups. The salient points of each group are given.

1. Radio - Direct transmission from a local base station controls individual receivers mounted on the customers apparatus. The location of the controlled appliance must be within the transmitter service area.

This is a relatively simple scheme to apply based on well known equipment technology. It is particularly suitable for areas which have a good operating history of VHF two way land mobile radios. A prime advantage is the complete independence from the power system and operating routines.

The disadvantages become apparent in areas having mountainous characteristics and in locations where frequency congestion renders the system prone to interference. (Section VI)

2. Low frequency power line carrier - Communication between one or more injection stations and the controlled customer by means of a signal superimposed upon the power line conductors. The signal frequency is below 1000 Hz to maximize the range of the signal.

This is a well tried communication system capable of relatively long range transmission. Of the two signal systems available, rhythm and multibit codes, the rhythm is the least susceptible to interference but has a restricted number of commands available.

Disadvantages are that the system is particularly sensitive to network switching and the arrangement of the HV/MV substations. The application to radially connected systems may involve a number of relatively expensive injection stations. Equipment involved in the injection stations is large, requires substantial power supplies and major additions to the power system in the form of fully protected feeder circuits. (Section VI)

3. High frequency power line carrier - Communication between injection points and the controlled customer by means of a signal superimposed upon the power line conductors. The signal frequency may range between 5 kHz and 200 kHz, depending upon the equipment type. This is a relatively new application and because of the higher frequency, is capable of more intelligence in the signal code with transmission at a somewhat higher speed than the low frequency system. Both one and two way communication is available.

As the signal frequency is much higher than the power frequency, attenuation effects are more severe and the signal range is less than the low frequency types. The requirement for many injection points to overcome the range defect results in small and relatively low cost units. These units are located on the MV system and are largely immune from power system switching problems.

Because of the larger message handling capabilities, the equipment is relatively complex and requires more elaborate control center equipment than other systems. (Section VI)

4. Hybrid - A system combining the advantages of both radio and high frequency power line carrier.

The technique is similar to a radio system but with the receivers located on the secondary wiring of the low voltage distribution transformer. The radio receiver retransmits the signal received as a high frequency power line carrier signal to carrier receivers located at all controlled customers appliances fed from the low voltage winding of the transformer.

This system has most of the advantages of a pure radio system in that it is immune to network operation and switching plus the ability to spread the cost of the radio receiver over several controlled customers. Likewise, the same disadvantages of a radio system are common to the hybrid scheme. (Section VI)

5. Telephone and direct wire systems - A relatively modern application using the high quality telephone company system. Very high speed, unique address signal capability is available using the telephone company central station equipment and lines without disturbance to the telephone customer. One way communication in either direction or full two way communication is possible with a minimum of equipment either at the utility end or at the customer location.

The disadvantages at the present time are limited to the legal and political aspects of cooperation between the utility and the telephone company and the area of responsibility of each. (Section VI)

F. Evaluate the Load Control Strategy

Select a load control strategy that maximizes the objective determined in X-1A1. The following procedure develops a load control strategy for peak shaving. Develop a reliable data base to forecast the daily load profiles, controllable load and restore demands of applicable appliances:

1. Develop the control target - Subtract the controllable load (Section III) from the system peak. The load profile may limit the percentage of controllable load that can be utilized. (A flat profile, for example, would cause a long control period which may produce adverse customer reaction.) The control target level determines the number of days that will need control. (Section IV)
2. Develop the priorities of controllable loads - Establish which appliances represent the most load and can be most reliably inhibited. Establish which appliances can be used to "fine tune" the load shed. Air conditioner loads, for example, will require cycling of inhibit commands to avoid customer inconvenience. Water heaters can undergo continuous inhibits for several hours. Irrigation loads may have uninterruptible periods. Payback periods of certain appliances may be long to avoid secondary peaks, increasing the probability of customer inconvenience. (Section IV)

3. Develop real time metering or monitoring system - Develop an adequate responsiveness to load changes. (A sampling program utilizing selected substations, for example.)
4. Develop control tactics - Divide controllable load into the number of independent/controlled groups, the number of which is limited by ease of operation and hardware capability. Select the members of any one group randomly to avoid political and regional diversity problems. Inhibit and restore loads according to priorities established in #2. Minimize and equally distribute off times to all controlled groups. (Section IV)
5. Evaluate limitations imposed by contractual agreements - For example, extend the load control to other seasons if a ratchet clause in a purchase power agreement necessitates.
6. Develop level of control desired - Determine if a secondary level of control (at a certain substation, for example) would be advantageous. Evaluate what proportion of substation peaks occur of same time as system peak. Unless a particular substation serves a single load, reject this control level if percentage is too low. (Control strategies have been developed for the four types of utilities evaluated in the Appendix A case studies.) (Section IV-D)

II. BENEFITS

A. Identify Savings or Capacity Changes

1. Existing Rate

- a. Verify amounts shown on recent year purchased power invoices from supplying utility(ies) by computing bills using existing tariff and monthly billing determinants. Note

the effect that the level of capacity charge and the ratchet provision (if applicable) has on the total purchased power bill, since it is through these provisions that savings accrue.

- b. For the twelve month period, estimate the change in monthly billing determinants corresponding to the amount of potentially controllable load and load control strategy.
- c. Recompute purchased power bills for the twelve month period using the revised billing determinants. The reduction in purchased power bills represents the annual savings.

Assumptions related to above computations:

- a. no growth or attrition of controlled customers is considered.
- b. existing rate is continued.
- c. the revised load pattern, as estimated, does not change.
- d. consequences from load control on power supply or the organizational structure of the non-generating utility are not considered above.

For example, if the non-generating utility is a member of a Generating and Transmission Cooperative, or in any other manner represents a significant part of the load of the supplying utility, it is unlikely that the simplified analysis outlined above would be entirely applicable.

2. Proposed Rate - After load control is implemented.

- a. Review the cost support of the existing rate(s) as filed or available from the power supplier(s) (generating utilities). Determine the methods with which the annual

revenue requirements of the non-generating utility are computed (e.g., the capacity allocation factors if appropriate).

- b. Determine the effect on the annual revenue requirements from the load control strategy employed. Estimates or detailed discussion with the supplying utility may be required. The timing of proposed rate adjustments must be considered, as well as the necessity of coordinating the load control program with the supplier and possibly other non-generating utilities who may be related organizationally.
- c. Using the probable rate structure and billing determinants of the proposed rate, calculate the monthly and annual purchased power costs.

3. Develop Levelized Annual Benefits

- a. Project capacity cost savings due to load control over the life span of control apparatus. An escalation factor recognizing potential future increases in purchased power rates is appropriate for this purpose.
- b. Develop present worth factors for each forecast year. The present worth factor for year n derives from the following formula:

$$PWF = \frac{1}{(1 + i)^n} \quad \text{Where } i = \text{cost of money}$$

- c. Develop the present worth of each future year's capacity cost savings as the product of the savings as projected under "a" above and the present worth factor determined under "b".

- d. Accumulate present worths of each forecast year's capacity cost savings.
- e. Convert cumulative present worth to a levelized annual equivalent amount through application of an annuity factor developed from the formula:

$$\text{Factor} = \frac{i}{1 - v^n}, \text{ where } Vn = \begin{array}{l} \text{present worth factor} \\ \text{in final year } n \end{array}$$

B. Ancilliary Benefits

- 1. Identify other functions, if any, which may be accomplished in conjunction with load control. Included among these may be:

Capacitor switching
Remote Meter Reading (two way system)
Distribution automation functions

- a. Develop actual or estimated costs of otherwise accomplishing the same function.
- b. Escalate costs as appropriate to reflect future costs over the life span of load control apparatus as amended to accomplish ancillary functions.
- c. Develop levelized annual benefits of ancillary functions by applying procedures outlined under item II-A-3 above to future cost streams representing alternative means of accomplishing the same function.

III. COSTS

A. Identify installed costs of technically feasible control systems. Carefully evaluate vendor quotation on prices, as significant additional costs may be required for the purchase of support equipment and installation. (Section VI)

1. Direct vendor costs - component costs for vendor supplied equipment. (Section VI)
2. Indirect non-vendor costs - includes support equipment, communication links, installation, maintenance, initial tests, and debugging. (Section VI)

B. Identify operation and maintenance expenses:

Operation and maintenance costs will vary somewhat between different equipment types but may be classified broadly as follows.

- 1) Central Control and Telemetry - Maintenance/of telemetering and central control equipment is expected to be minimal with simple one way equipment and will be restricted in the main to periodic cleaning, inspection and recalibration. It must be recognized that the maintenance will increase significantly with the increase in complexity such as will be encountered with fully automated remote meter reading capability.
- 2) Signal Source Equipment - This equipment will vary according to the control system and will consist of the following:

Radio	- radio transmitter
Low Frequency Power Line	
Carrier	- Injection equipment (high power)

High Frequency Power Line

Carrier	- Injection equipment (low power)
Hybrid	- Radio transmitter and VHF receivers
Telephone	- Not applicable

Maintenance for the radio transmitters and low power high frequency power line carrier equipment are expected to be minimal and limited to periodic inspection and calibration checks. It is anticipated that maintenance on line mounted signal injection equipment used in some carrier applications would be at a central location with a field changeout of the defective unit. Maintenance of the low frequency high power injection stations is more expensive and will be comparable with similar size substation equipment.

- 3) Communication Links - These links between the central control and signal sources may be radio or leased telephone lines. Maintenance charges for radio systems would be minimal, as referenced above while charges for leased lines would be a fixed monthly charge dependent upon the number and length of line involved.
- 4) End Use Receivers - These receivers would be subject to a change out program similar to defective house service meters. A central repair/recalibration facility may or may not be economic depending upon the volume of units processed. Alternatively, contract repair or factory reconditioning may be considered.

C. Develop Levelized Annual Costs

1. Express project costs in terms of revenue requirements from ultimate consumers by developing a fixed charge rate incorporating:

- a. Capital Recovery Factor, consisting of:

- (1) The weighted cost of money, expressed as a percent and

- (2) Sinking fund depreciation factor developed from the formula:

$$\frac{i}{(1 + i)^n - 1}$$

where i = cost of money and n = the service life of the load control system under analysis.

- b. Property tax rate, if appropriate

- c. Property insurance rate, if applicable

- d. Levelized annual income taxes, if applicable (For a sample development of levelized annual income tax component, see Case #1 accompanying to this report).

2. Apply Fixed Charge Rate to installed apparatus costs for alternative systems to develop levelized annual fixed costs.

3. Project operation and maintenance expense over apparatus service life by applying a suitable escalation factor.

4. Develop annual equivalent operation and maintenance expenses by applying the present worth and annuity factor technique outlined under item II-A-3 above and further described in Section VIII of this report.
5. Develop total annual equivalent costs as the summation of levelized fixed costs (III-C-2) and levelized operation and maintenance expenses (III-C-4).

IV. SELECTION OF OPERATIONAL SYSTEM

A. Benefit/Cost Ratio

1. Identify annual equivalent benefits including levelized capacity cost savings and any ancillary benefits associated with alternative load control systems (from II-A and II-B above).
2. Identify annual equivalent costs for each candidate system as defined in III-C above.
3. Develop Benefit/Cost ratio for each candidate system.

B. Payback Period

1. Develop net annual benefits as the remainder after subtraction of annual operation and maintenance expenses, property taxes and income taxes if applicable. Note that for this purpose, all benefit and cost streams are on an actual projected basis, i.e., before application of present worthing techniques.

2. Accumulate net benefits for each year until cumulative net benefits equal or exceed raw cost of load control apparatus.
3. Determine payback period as elapsed years (or fractions thereof) required to recover original costs for the respective systems.

C. Analysis of Results

1. All other things being equal, the optimal system may be determined as:
 - a. That system with the highest ratio (exceeding unity) of project benefits to costs.
 - b. That system having the shortest paybeck period.
2. Sensitivity Analyses - Alternative results should be developed based on variations of significant input factors such as:
 - a. Customer acceptance rates.
 - b. Escalation factors.
 - c. Capital cost variations.
 - d. Operating expense variations.
3. Project revaluated on basis of alternative conclusions derived as a result of sensitivity analyses.
4. Consideration should be given to the ability of individual systems to provide for auxiliary functions at some future date if the potential for such applications is reasonably foreseeable.

5. The ultimate test of project feasibility lies in the application of sound judgement to the tangible results of evaluation analysis and the intangible factors otherwise affecting the potential for load control.

BIBLIOGRAPHY

Arkansas Power and Light Company, "Peak Load Control Study, Summer of 1975".
Distribution Standards Section. Arkansas Power and Light Co.
October 6, 1975. Rev. January 12, 1976.

_____, "1976 Peak Load Study". October 29, 1976.

Barrett, A. W. (Cobb EMC), "A Report of An Effective Load Management System
Second Year's Operation". Paper presented to Cobb EMC members,
Marietta, Georgia, 1977.

Beaty, H. Wayne, "Automated Distribution; Improves System Operations and
Reliability". Electrical World. July 15, 1977. p. 39-50.

Bentley, Charles E. (Plessey Chartsworth), "Irrigation Pumping Management
with Rhythmic Ripple Control". IEEE 1977 Rural Electric Power
Conference. Kansas City, Mo. May 15-17, 1977, (c77 355-1 IA).

Berkowitz, David G. (Westinghouse Electric Corporation, Pittsburgh, PA),
Samuel A. Jordan and Donald L. Nickel. "A Look at Load
Management for Non-Generating Utilities". NRECA Technical
Conference. St. Paul, Minn. June, 1976.

Central Illinois Light Company Load Management Studies - Report to Illinois
Commerce Commission, December 21, 1978.

"Cooling-demand Controls Look Good". Electrical World. July 15, 1976.
p. 96-98

"Demand Controller Shaves Winter Peak". Electrical World. October 1, 1976.
p. 92-93.

Ehlers, Eldon G. (EPRI), "State of the Art of Utility Industry Heat and
Cool Storage Programs". 1978 APPA Engineering and Operations
Workshops. March 1, 1978.

Electric Utility Rate Design Study. Task Force 9. "Mechanical Controls
and Penalty Pricing, Topic 9". EPRI. January 14, 1977.

_____. Arthur D. Little, Inc. "Topic 7: Metering and Communication
Systems; Topic 8: The Utilization of Off-Peak Electricity; Topic 9:
Mechanical Controls and Penalty Pricing". EPRI January 15, 1977.

_____. Task Force 8. "Technology for Utilizing Off-Peak Energy.
Task Force 8". EPRI October 15, 1977.

E.T.K. Law, Pacific Gas & Electric Company's Residential Central Air Conditioning Load Control Experiment. EPRI Workshop in "New Modes of Residential HVAC; Economic Incentives and Barriers" January 14-17, 1979 Tampa, Florida

Ford, Frederick A. "On the Reduction of the Peak Demand for Electricity in the State of Vermont". PhD dissertation. Thayer School of Engineering, Dartmouth College. Hanover, New Hampshire. July 4, 1973.

Haddock, Graham. "VHF and UHF Radio Interference". Presented, American Public Power Association. Eng. and Operations Section. February 28, 1978.

Haipton, Ricard M. Load Management Standards, Staff Report. California Energy Commission. June 5, 1978.

Hastings, B. F. "Manage Loads to Reduce Capacity Needs". Electrical World. November 15, 1975. p. 92-94.

Holtzinger, James S. "Case Studies in the Application of Radio Control for Load Management". Presented, Institute for Public Utilities. Williamsburg, Virginia. December 12-14, 1977.

Jack, Charlie F. "G & T Cooperative Looks at Load Management". Presented, National G & T Managers Association Meeting. San Antonio, Texas. October 18, 1976.

Jack, Charlie F. "Peak Shaving - A Way to Fight Rising Costs". IEEE Transactions on Industry Applications. Sept/Oct., 1976. p. 486-491.

Jack, Charlie F. "Peak Shaving Slices High Demand". Electrical World. January 15, 1976. p. 46-47.

Kaplan, Gadi, "Two-Way Communication for Load Management". IEEE Spectrum. August, 1977. p. 47-50.

Kniel, R. "Simulation and Real Time Load Management Operations of Distribution Systems by Computer and Ripple Control". Power Industry Computer Applications Conference. 1977. p. 343-349.

Laaspere, Thomas, The Technological Alternatives for Metering and for Load Management, Testimony Before the Public Service Commission of New York. August 11, 1975 (Case No. 26806). U.S. D.O.E. Technical Information Center. Oak Ridge. (NP-20674).

Laaspere, Thomas, et al. "Creative Electric Load Management". IEEE Spectrum. February 1975, p. 46-50

"Load Management Studies Get Underway". Electrical World. August 1, 1975.
p. 70-71.

Lokken, Glen, et al. "The Wisconsin Electric Power Company Load Management Experiment". American Power Conference, Proceedings. Vol. 38. 1976.
p. 1369-1374.

Militello, Philip G. "Concepts in Demand Control". Public Utilities Fortnightly.
August 14, 1975. p. 29-34.

MITRE Corp. An Assessment of Communication Alternatives. EPRI. September, 1976.
(EPRI EL-157 Project 569). 2 vol.

Nelson, Melvin D. (Minnkota Power Cooperative, Inc.), "Load Management -
Ripple Control". Minnesota Power Systems Conference. October 12 & 13, 1976.

Oliver, James B. (Detroit Edison), "Radio Control of Water Heaters and Distribution
Station Voltage Regulators". IEEE Summer Power Meeting. Dallas, Texas.
June 22-27, 1969. (P 666-PWR).

Owens, Ken, "Success Stories Will Crack Utility Resistance to Load Management"
Electric Light and Power. March, 1977. p. 6-7+.

Paschen, Allen, M. B. Powell, and Earl Jaeger. "Carrier System Controls Load".
Electrical World. December 15, 1977. p. 55-57.

Potomac Edison Company. "Peak Management Demonstration Project of Residential
Load Controller". Customer Services Dept. PECO. April 14, 1976.

Pronty, C. W. and R. K. Marble. "Western Massachusetts Electric Company Study
Radio Control of Water Heaters". Presented to Meter and Service Committee
Electric Council of New England. Newport, R.I. May 3, 1973.

"Radio Control of Air Conditioners Looks Promising". Electrical World.
November 15, 1975. p. 117.

Rau, N. S. and R. W. Graham. (National Energy Board, Ottawa). "Analysis and
Simulation of the Effects of Controlled Water Heaters in a Winter Peaking
System". IEEE Power Engineering Winter Meeting. New York, N.Y.
January 29 - February 3, 1978. (IEEE F 78-077-0).

Residential Electric Space Heating; Load Research Project. Pacific Gas & Electric Company. March 1967.

Roberts, Robert L. (Pioneer Rural Electric Cooperative), "Load Factor Improvement Through Radio Controlled Diversity". 1973 Rural Electric Power Conference. Minneapolis, Minn. April 30, 1973.

Roberts, Robert L. "Study Proves Peak-Shaving by Radio". Electrical World. July 1, 1973. p. 48-49.

Schill, Robert E. "Load Management - Innovations and Techniques". Public Utilities Fortnightly. January 15, 1976. p. 17-21.

Serfass, J. A., et al. "Field Demonstrations of Communications Systems for Distribution Automation". IEEE Region 6. Conference Record. Electronics for Resources Management. Alamogordo, N.M. April 1978.

Stetson, L. E., D. H. Husted, and F. J. Potthoff. "Ripple Control of Irrigation Loads at Southwest Public Power District". U.S. Dept. of Agriculture, Agricultural Research Service. Proceedings, 1977 Nebraska Irrigation Short Course, Lincoln, Nebraska. January 24-25, 1977.

Stetson, L. E. and John W. Addink. "Controlling Electrical Peak Demands". Nebraska Irrigation Short Course. Lincoln, Nebraska. January 26, 27, 1976.

Stetson, L. E., (U.S. Dept. of Agriculture. Agricultural Research Service, Lincoln, Nebraska). and Ivan D. Nelson (Custer Public Power District). "Irrigation Scheduling to Control Electrical Demand". Nebraska Irrigation Short Course. Lincoln, Nebraska. January 20-21, 1975.

"Study Proves Peak Shaving by Radio". Electrical World. July 1, 1973. p. 48-9.

Sulzberger, U. T., et al. "The Potential for Application of Energy Storage Capacity on Electric Utility Systems in the United States". IEEE Transactions on Power Apparatus and Systems. Part I. Vol. PAS-95. No. 6, Nov./Dec. 1976. p. 1872-1881. Part II. Vol. PAS-96. No. 1, Jan./Feb. 1977. p. 213-221.

"Survey Scrutinizes Load Management". Electrical World. July 15, 1976. p. 76-7.

Systems Control, Inc. Critical Analysis of European Load Management Practices.
U.S. ERDA. January 1977. (CONS/1168-1).

"Test Management of Air Conditioning". Electrical World. August 15, 1976.
p. 70-71.

"Two Innovative Rates Get High Marks". Electrical World. November 1, 1976.

U.S. ERDA, Division of Electric Energy Systems. Program Plan For Research, Development and Demonstration of Load Management on the Electric Power System. February 1977, ERDA 77-40.

VanHeck, J., et al. "Ripple Control - A Proven Load Management Tool".
American Power Conference, Proceedings. 1976. Vol. 38. p. 1375-1380.

Weatherby, Paul (Cobb EMC), "More Than a Jingle in the Pocket". Load Management Conference. Kansas City, Mo. April 19, 1977.

Williamson, R. W. (San Diego Gas and Electric Company). "Application of Distribution Power Line Carrier for Distribution Automation, Load Management and Customer Metering". Pacific Coast Electrical Asso. Engineering and Operating Conference. Los Angeles, CA. March 17, 1977.

OTHER SOURCES

Personal interviews were conducted with representatives of several utilities testing or implementing load control systems. Those utilities were:

Arkansas Power & Light Co. Little Rock, Arkansas	Georgia Power Company Atlanta, Georgia
Buckeye Power, Inc. Columbus, Ohio	Green Mountain Power Burlington, Vermont
Central Vermont Public Service Corporation Rutland, Vermont	Minnkota Power Coop, Inc. Grand Forks, North Dakota
City of Burbank Burbank, California	New England Electric System North Andover, Massachusetts
Cobb County R.E.M.C. Marietta, Georgia	Wisconsin Electric Power Company Milwaukee, Wisconsin
General Public Utilities Parsippany, New Jersey	

Other utilities were contacted at various times for their work in load research or customer surveys:

Arkansas Power & Light Company
Baltimore Gas & Electric Company
Central & Southwest Corporation
Cobb County R.E.M.C.
Consumers Power Company
Detroit Edison Company
Duquesne Light & Power Company
Exeter & Hampton Electric Company
Georgia Power Company
Hartford Electric Light Company
Houston Lighting & Power Company
Iowa-Illinois Gas & Electric Co.
Long Island Lighting Company
Ohio Power Company
Oklahoma Electric Cooperative
Pacific Gas & Electric Company
Public Service Electric & Gas Co.
Southwestern Electric Power Company
Texas Power & Light Company
United Rural Electric Membership
Cooperative
Wisconsin Electric Power Company
Western Massachusetts Electric Co.
West Penn Power Company