ELECTRIC UTILITY REGULATORY ASPECTS OF ELECTRIC VEHICLE COMMERCIALIZATION

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EXECUTIVE SUMMARY

This report was undertaken at the request of the Institute for Interdisciplinary Engineering Studies to analyze certain of the public utility regulatory factors that would potentially affect the commercialization of electric vehicles. The report provides background information on the electric utility regulatory process, considers the effect of electric vehicle demand on utility loads and revenues, discusses the likely involvement of utilities and regulators in a commercialization program, and analyzes the economic incentives and disincentives for large-scale electric vehicle usage from the viewpoint of utilities and state regulators.

Due to the high demand for petroleum products in the transportation sector of the U.S. economy, electric and hybrid vehicles are being considered as an alternative form of private and commercial transportation. To this end, the U.S. Congress enacted the Electric and Hybrid Vehicle Research Development and Demonstration Act of 1976 for the purpose of reducing petroleum demand in domestic transportation by substituting electric and hybrid vehicles for some portion of the fleet of internal combustion engine vehicles.

Electric and hybrid vehicles are powered by electric motors or a combination of electric motor and internal combustion engine. As such, these vehicles represent a potentially significant new demand on the nation's electric utilities because of the need for recharging the vehicles' batteries. The nature of this demand and its impact on electric utility systems are important factors for the successful commercialization of electric and hybrid vehicles. The price of electricity used to power these vehicles partially determines their relative cost-competitiveness with liquid-fueled vehicles.

Due to the lack of detailed projections of hybrid vehicles load characteristics, this report considers only the likely impact of electric vehicles (EVs) on electric utility systems and the possible regulatory considerations attending that impact. Nevertheless, most of the discussion of regulatory policy would apply equally to both vehicle types. Several estimates of the number of EVs likely to be in operation over the near future have been undertaken with predictions varying from 92,000 vehicles in 1983 to 13 million by the year 2000. Because of the limited range and speed of these vehicles, ownership is considered likely to be concentrated in urban areas for commuting and short-haul commercial uses.

The impact of electric vehicles on the cost of electric utility service will be an important factor in determining the price of electricity used for powering these vehicles. At the present time, this impact is speculative due to the uncertainty of information on EV use patterns, degree of market penetration, and likely geographic concentration. Nevertheless, the following regulatory trends will be significant.

The current movement toward cost-of-service pricing in the electric utility industry, as emphasized by the Public Utility Regulatory Policies Act of 1978, and as reflected in the current cost structure of the industry, requires that each type of service be charged rates that adequately reflect the costs of providing that service. The analysis contained in this report indicates that a significant cost savings to the utility may be achieved if electric vehicle demand on the electric system is confined to off-peak periods. All or a portion of this cost saving could be passed along to electric vehicle owners if time-of-day pricing for electricity is instituted, although metering costs need to be considered and would likely reduce the cost savings to the vehicle owner. This reduction in operating costs to the EV owner is likely to have a positive effect on the commercialization of electric vehicles while also providing potential benefits to the utility in terms of increased revenues and improved system load factor. The existence and magnitude of these possible benefits and cost reduction, however, depend critically upon the load characteristics of the individual utility and the usage patterns of EV owners.

Off-peak charging of electric vehicles also represents the greatest potential for displacement of petroleum use in the transportation sector. This is so because new baseload electric generating units are predominately coal and nuclear fueled while cycling and peaking units are largely fueled by petroleum products, although considerable regional variation in fuel supplies exists, and so this generalization is not universally true. Significant displacement of petroleum use in the transportation sector, then, is most likely to be achieved if electric vehicles can be charged mostly during off-peak hours.

The degree of electric utility and state public utility commission involvement in an EV commercialization effort may have an important effect on the level and timing of EV use. Utilities have traditionally been involved in activities in unregulated markets in addition to their primary function of providing electric service in a regulated market. The degree of that involvement has been reduced over the past decades and its emphasis has shifted from one of promoting electric consumption to that of encouraging energy conservation. The opportunity for electric utilities to participate in EV commercialization by offering sales, leasing, and/or servicing of electric vehicles--a movement in the counter direction--may provide some benefit to the utility and its customers but would require regulatory commission oversight and approval. Regulatory agencies have generally required separate subsidiary corporations for monopoly and competitive lines of business to avoid cross-subsidization.

Major incentives toward electric vehicle commercialization include the fact that electric utilities currently have a relatively high level of reserve capacity available to meet this new demand. Increased revenues to the utilities without the necessity of expanding system capacity if EV use is confined largely to off-peak periods is also a potentially strong incentive, as is the possibility of utility involvement in sales, leasing, and/or service of EVs. A possible disincentive to utility involvement is the potential for electric vehicles to promote competition within the electric utility industry, although the EV customer would likely benefit from this competition. Competition among utilities might increase due to the mobility of the EV customer.

A potential regulatory issue is the transfer of road-use taxes from inclusion in the price of gasoline to inclusion in the price of electricity. These taxes could be added onto the price of electric service provided to EVs; however, separate metering of EV demand would probably be required.

PREFACE

This report was prepared by The National Regulatory Research Institute (NRRI) for the Institute for Interdisciplinary Engineering Studies at Purdue University. Chapters One through Four were prepared by Russell J. Profozich, senior institute economist with NRRI. Chapter Five was prepared originally by Dr. Richard A. Tybout, professor of economics at The Ohio State University.

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TABLE OF CONTENTS

CHAPTER 1

INTRODUCTION

Several studies have been conducted to estimate the potential for commercialization or market penetration of electric vehicles in the United States. The purpose of this report is to address some of the regulatory aspects of electric vehicle impact on electric utilities and the regulatory considerations needed to deal with this impact. Market penetration is taken as a given for the purpose of this report.

In the United States, approximately 85 percent of transportation energy use is consumed by highway vehicles. Ninety-six percent of all transportation energy is derived from petroleum; only 1 percent from electricity. Over 52 percent of all refined petroleum products used in the United States is for transportation purposes;[1] by far the predominant mode of transportation is internal combustion engine vehicles. In light of the above information, electrification of passenger vehicles and other highway vehicles is receiving increased attention as a method of conserving scarce domestic petroleum resources and reducing our dependence on imported oil supplies. Other advantages such as reduced fuel emissions may also be achieved through the substitution of electric vehicles for fossil-fueled vehicles. To this end, the United States Congress enacted the Electric and Hybrid Vehicle Research, Development and Demonstration Act of 1976 (Public Law 94-413). The purpose of the act is to reduce the nation's dependence on foreign petroleum sources by reducing domestic transportation demand which can be accomplished by substituting electric and hybrid vehicles for internal combustion engine vehicles in short-haul, low-load applications.

The Congress charged the Energy Research and Development Administration (ERDA), now a part of the Department of Energy (DOE), with

[1] Energy Conservation for Transportation,(Washington, D.C.: United States Department of Transportation, Technology Sharing Office, January 1979), p. 99.

responsibility for administering PL 94-413. ERDA commissioned the Institute for Interdisciplinary Engineering Studies at Purdue University to perform an independent evaluation of the opportunities and risks associated with electric and hybrid vehicle commercialization. As a part of that effort, the Institute has contracted with The National Regulatory Research Institute (NRRI) to perform a preliminary evaluation of the electric utility regulatory aspects of electric vehicle commercialization. This report is the end product of that evaluation.

Electric vehicles (EVs) are similar to internal combustion engine vehicles (ICEVs) except that they are powered by a battery or series of batteries that store electric energy. This energy is used to power the vehicle and thus displaces gasoline--a petroleum derivative--in transportation use. Once the energy stored in the battery is expended, the battery may be recharged for the next day's use. In this regard, electric vehicles represent a new source of demand for the nation's electric utilities.

Hybrid vehicles (HVs) operate on a combination of electric battery and internal combustion engine. The battery is used to propel the vehicle at low speeds for relatively short distances. Once a maximum speed is reached, the gasoline-fueled internal combustion engine displaces the battery as a fuel source and propels the vehicle at higher speeds and longer distances. Thus HVs have the potential to conserve petroleum resources while allowing the vehicle to achieve higher speeds and greater distances than obtainable with battery power alone.

Electric vehicles and hybrid vehicles have the potential to displace large amounts of petroleum use in the transportation sector if they can be developed as a cost-effective alternative to conventional ICEVs. Also, the electricity used to power these vehicles must be generated from an energy source other than petroleum, such as coal or nuclear energy. Electricity produced from oil-fueled generating plants offers little, if any, real net savings in petroleum resources if used to propel electric and hybrid vehicles.

Chapter 2 of this report provides general background information on the electric utility ratemaking process, and how traditionally and under new federal laws, it would most likely deal with the introduction of a new load (demand) on a utility's system. Chapter 3 contains an analysis of the probable impact of EVs on utility load characteristics and revenue requirements including a discussion of the effects of variations in utility fuel supplies. This section also contains an analysis of the likely effect of various utility rate structures on the pricing of electrical service provided to EVs. Chapter 4 contains a consideration of the possible degree of utility company and regulatory commission involvement in an EV commercialization program and the likely impact of that involvement. In Chapter 5 is a discussion of related utility or regulatory incentives (or disincentives) to the commercialization of EVs and possible action on behalf of utilities and state and federal regulators to deal effectively with these incentives/disincentives. Emphasis is placed on allowing Evs to compete with other end-use applications of electricity on a true cost-of-service basis, rather than artifically impeding or promoting their use.

Before beginning the analysis, it should be noted that as with the introduction of any new technology, the estimates of demand for and supply of EVs and EHVs are necessarily general in nature and subject to wide variability. The same is true of estimates of their electric load characteristics and impact on utility systems. Therefore, while PL 94-413 addresses itself to the commercialization of both electric vehicles and hybrid vehicles, this report will deal exclusively with the introduction of electric vehicles and their impact on utility systems. This approach is taken for several reasons. First, the technology of EVs is much further developed than that of HVs and accordingly, the predominant share of available information is on EVs. Second, any commercialization of these alternative-fuel vehicles over the foreseeable future will involve almost exclusively EVs rather than some combination of EVs and HVs. Since EVs are powered exclusively by electricity, an analysis of their electric load characteristics will offer an estimate of the maximum impact of a commercialization program on electric utilities. Any substitution of HVs for EVs during this commercialization period would serve to lessen the effect, in terms of total electricity use, on electric utility systems. Finally, the number of HVs in use over the near-term future is expected to be small, the impact of their substitution for EVs on the analysis, therefore, is also quite small.

CHAPTER 2
THE REGULATORY FRAMEWORK

Electric vehicles will affect the load characteristics and therefore the cost of providing service of electric utilities. An analysis of this impact is necessary to determine the cost of electricity used to power these vehicles. Because electric utilities are subject to the authority of various regulatory commissions, this analysis necessarily involves a discussion of the ratemaking process. It is within this process that the regulatory issues involved in EV commercialization must be analyzed and resolved. Therefore, this report opens with a brief discussion of the regulatory mechanism.

Electric utilities are considered to be "natural monopolies"; that is, it is more efficient for one company to serve an entire territory than to have competition among several companies. This monopoly position eliminates the necessity to duplicate facilities and allows a utility to reach economies of scale and larger volumes of sales than would otherwise be possible to achieve. Due to the capital intensity of utility investment, economies of scale are an important mechanism in achieving low-unit costs of service. In exchange for their monopoly position, electric utilities promise to provide adequate service to all customers within their service territory at an established minimum level of reliability and at a just and reasonable price. Electric utilities are also subject to the authority of various state and federal regulatory agencies. The purpose of these agencies is to ensure that the utility companies provide adequate service at a fair price while having the opportunity to earn a fair return on their investment.

In regard to ratemaking matters, electric utilities are regulated at the state level by the various public utility commissions, and at the federal level by the Federal Energy Regulatory Commission (FERC). The state commissions regulate retail sales of electricity, approximately 80 percent of total sales on a national basis, while the FERC regulates wholesale sales in interstate commerce. Both types of agencies use similar practices to regulate electric utilities, and since the introduction of EVs will affect exclusively retail sales of electricity, we will concentrate on the state regulatory mechanism.

State public utility commissions regulate electric utilities by first determining the total amount of investment of the company in plant and equipment "used and useful" in providing service to its customers. This investment is termed the utility's rate base. The rate base is the depreciated total dollar investment in land and facilities used to provide electric service and includes the value of generating facilities, transmission and distribution (T&D) equipment, customer-related equipment including line drop and meters, and general facilities including office buildings, service trucks, and inventory. The total depreciated value of these facilities is annualized to determine the yearly revenue requirement of the utility needed to recover the cost of this investment.

To this "fixed cost" of investment is added the utility's annual variable cost of service. This cost includes operating and maintenance (O&M) expense including labor and fuel costs, meter reading and billing costs, and an allowance for working capital (i.e., funds to meet short-term expenses). Finally, the utility commission must determine the utility's cost of capital as a part of its determination of a fair rate of return on investment. This is necessary for the utility to attract financial capital with which to expand its facilities to meet the growing demand for electricity and to provide a return to those who have invested their funds with the company. The utility's total annual revenue requirement, then, is equal to the annualized cost of plant and equipment plus operating and maintenance expense plus profit.

Traditionally, utility commissions have used a utility's historic level of investment and expenses to determine its annual revenue requirement. A "test year" is used, which is usually the latest 12-month period for which data are available, to determine the depreciated value of investment and the operating and maintenance expense of the company. To this is added the utility's current cost of capital in order to derive the total annual revenue requirement of the company. This procedure presents some difficulties during inflationary periods when a utility's rate base and O&M expense may be increasing faster than its revenues. (This is so because its revenue requirement is based upon historic or embedded costs that may be lower than current costs.) In addition, over the past several years, electric utilities have not been able to reach further economies of scale sufficient to offset increasing costs of plant and equipment. Therefore, new plant and equipment often cost more than "old" plant and equipment, causing the utility's cost of service to increase still further above its revenue requirement as determined by its historic rate base. As a result, public utility commissions have employed several mechanisms to increase the annual revenue requirement of electric utilities. These mechanisms include allowing utilities to include a part of the cost of constructing new generating facilities in their rate base before the facilities are completed and thus "used and useful" in providing service, and employing a future test year that uses estimates of the future level of investment and expenses, say over the next 12-month period rather than over the last 12-month period, in determining the company's annual revenue requirement. Perhaps the most important area of electric utility regulation where state regulatory commissions have employed the economic concept of increasing costs of investment is in setting rates (prices) for electric service. This mechanism is taken up in the following paragraphs.

Electric Utility Rate Structures

Once a utility's annual revenue requirement is determined, the utility, with the approval of the state regulatory commission, must translate this revenue into rates. Traditionally, these rates have been based on the average of historic and current costs of providing service and have declined with increased consumption of electricity. This form of pricing is no longer believed to be appropriate by many industry analysts. State public utility commissions, with some impetus from the federal government, have begun to alter electric utility pricing schedules to reflect more accurately the current cost structure of the industry. This developing pricing format is based on the economic notion of marginal cost and is one method of having electric utility prices more accurately reflect the cost of providing service. A second method, that of basing rates on time- differentiated average costs, is also being implemented.

Economic theory holds that economic efficiency is achieved when the price for any product or service is equal to the marginal cost of providing that product. In this way, customers pay an amount to purchase the product equal to the cost of producing it.[2] While marginal-cost pricing logically is an appropriate pricing mechanism for any industry whether it is experiencing increasing or decreasing costs of production, this concept is particularly important to the electric utility industry where dramatic cost increases have occurred and energy conservation policies have been implemented.

The regulatory doctrine of fairness states that the rate charged each customer and each customer class must be "just and reasonable" and not "unduly discriminatory." This means that electric utility rates must be based on the costs of providing service, and no single customer or customer class should receive service at an artificially low or artificially high price. During a period of inflation, marginal cost will be higher than past average costs. Basing electric utility rates on average cost, then, will tend to underprice electricity. The argument is that under this situation, customers have an incentive to overconsume electricity, since the price they pay for additional consumption is below the current cost of

[2]For a more detailed description of the principle of marginal cost pricing as it relates to electric utilities see, for example, Electricity Pricing Policies for Ohio, Vol. I, NRRI-77-1 (Columbus, Ohio: The National Regulatory Research Institute, 1977).

production. Utility companies also tend to suffer from revenue deficiency, since the cost of producing an additional kilowatt-hour (kWh) of electricity at various times of peak demand is above the price paid for its consumption. Finally, the regulatory doctrine of "just and reasonable" may be violated if price no longer adequately reflects the cost of service.

It has come to be increasingly recognized by regulators that the cost of producing a kWh of electricity also varies by time of day and season of year. This is so because electric utilities design their systems to meet peak demand, a condition that follows from their requirement to provide service to all customers within their service territory on demand. To meet the total demand on their systems, utilities install several types of generating facilities.

New "baseload" plants are usually coal-fired or nuclear facilities that are highly capital intensive but use relatively low-cost fuel. These plants produce electricity at the lowest cost per kWh because they are designed to operate during most of the hours in a year, and thus the capital costs are spread out over a large number of units of output.

Intermediate or "cycling" plants are generally less capital intensive and use more costly fuel than baseload plants and are intended to meet demand on the system above that supplied by the baseload facilities, as such, they operate during fewer hours of the year. "Peaking" units are intended to supply power during periods of peak demand on the system. Because these plants are designed for a minimum number of hours of operation, they are small in size--generally 5 to 100 megawatts (MW) of capacity--and have low-capital costs but high-fuel costs. Due to this "mix" of generation capacity and the varying levels of demand on the system, it costs more to produce a kWh of electricity during peak demand periods than during off-peak periods. Peak periods occur on a daily basis --usually in midafternoon or early evening--and on a seasonal basis--during the hottest day in summer for a system with a large air conditioning demand or the coldest day in winter for a system with a large electric heating demand. Efficient pricing of electricity, then, would vary the price charged to reflect the different costs of production during peak and off-peak periods in addition to reflecting the increasing long-run costs of the industry, and at the same time would provide adequate annual revenues to the utility. This form of pricing is currently being considered by the various state public utility commissions and has been adopted by a few commissions. As pointed out earlier, time-differentiated pricing can as well be constructed on a traditional average-cost basis and does not require that a commission use marginal-cost approaches to achieve its rate design goals.

Federal Legislation

As the price of electricity (and other energy sources) has increased over the last several years, and with increasing levels of oil imports and developing shortages in energy supplies, the federal government has become increasingly active in developing a national energy policy. As a part of this policy, the Congress passed in 1978 the Public Utility Regulatory Policies Act (PURPA). The purposes of this act are "to encourage conservation of energy supplied by electric utilities; optimization of the efficiency of use of facilities and resources by electric utilities; and equitable rates to electric consumers."[3] This act establishes federal standards that state public utility commissions are required to consider and to implement if found to be cost-effective. A summary of the ratemaking standards follows:

1. Cost of Service--electric utility rates shall reflect the cost of providing service to the maximum extent practicable, as these costs vary by time of day and season of the year and reflect differences in costs of supplying additional capacity and kilowatt-hours.
2. Declining Block Rates--this rate form shall be eliminated unless found to reflect the costs of providing electric service.
3. Interruptible Rates---electric utilities must offer each industrial and commercial customer an interruptible rate that reflects the costs of providing this type of service.

[3] Public Utility Regulatory Policies Act of 1978, Public Law 95-617, 92 Stat. 3117, November 9, 1978.

4. Load Management Techniques--electric utilities shall offer electric customers such load management techniques that are found to be cost-effective, reliable, and provide energy or capacity management advantages to the utility. ("Load management techniques" means any technique other than a time-of-day or seasonal rate to reduce the maximum kilowatt demand on the electric utility, including ripple or radio control mechanisms and other types of interruptible electric service, energy storage devices, and load-limiting devices.)

Utility Regulation and Electric Vehicles

The introduction of a new load (electric demand) on electric utilities (whether in the form of electricity requirements of EVs or any other type of service) must be priced in a manner consistent with the current cost structure of the industry and consistent wih the recently imposed federal standards. The price of electricity consumed by electric vehicles, then, should reflect the cost of providing this type of service. This is not an easy task, at least not over the immediate future, since the exact nature of EV electric demand in terms of the number of vehicles in use, their geographic concentration, use pattern, and distribution between private and commercial ownership is not accurately known at the present time. A further complication is the fact that although state commissions are mandated to consider the above mentioned federal standards, the nature of the implementation of these standards is left to state commission discretion. According to PURPA, those standards determined not to be cost-effective need not be implemented. The widely differing circumstances of each electric utility ensure that pricing structures and cost of service allocations to the various customer classes and types of service will show considerable variation among the various utility service territories for the foreseeable future.

The uncertain nature of the impact of EVs on utility load characteristics, coupled with the varying nature of electric utility price reform, is illustrated by the fact that under many current circumstances the implementation of time-of-day pricing for residential customers is not cost-effective. While in most instances a seasonal price variation could be (and often is) implemented, pricing structures for residential electricity consumption generally follow the traditional declining block form (although considerable "flattening" of the rate structures, that is limiting the number of distinct pricing "blocks," is taking place). An example of this type of residential rate is presented in table 2-1.

TABLE 2-1

ILLUSTRATIVE SEASONAL
RESIDENTIAL ELECTRIC TARIFF

	Summer	Winter
Customer Charge per Month	\$7.00	\$7.00
Energy Charges		
First 750 kWh/Month per kWh	\$0.0415	\$0.415
All over 750 kWh/Month per kWh	\$0.0265	\$0.215

Source: Derived from rates filed by the Dayton Power and Light Company with the Ohio Public Utilities Commission

The total cost of providing electric service is composed of three types of costs: customer-related costs that do not vary with the level of consumption and include metering and billing costs and a small portion of distribution costs; demand-related costs that vary with the volume of demand placed upon the system and include the costs of generating facilities, most transmission and distribution costs, and fixed operating and maintenance expenses; and energy-related costs that vary with the number of kilowatt-hours consumed and include variable operating and maintenance expense and fuel costs.

In the above table, the customer-related costs are reflected in the monthly customer charge. This would be a minimum monthly charge even if no electricity were consumed. The demand- and energy-related costs are reflected in the energy charges. These charges vary by season of the year to reflect the greater demand placed upon the system during the summer months (summer energy charges for consumption over 750 kWh/month are higher than winter energy charges). In order to have a separate demand charge, additional metering equipment is necessary.

With this rate structure, all electric consumption during each season of the year above 750 kWh is priced at the same rate regardless of the time that the consumption takes place. A residential customer with an electric vehicle, then, would pay the same rate to charge his EV no matter what time of day he chose to plug it in. This type of pricing offers no incentive to the EV customer to charge his vehicle during low-cost, off-peak periods. As such, EV demand on the system is likely to be dispersed throughout the day to a greater degree than it would be if an off-peak discount rate were offered. However, if future events act to make time-of-day pricing for residential customers cost-effective due to increasing electricity costs and/or declining metering costs, one would expect a greater concentration of EV demand on the utility system and also on the costs imposed on the system since (as mentioned) costs of service vary with total system demand.

Price structures for electric service also have an effect on the commercialization of electric vehicles. A low-cost, off-peak rate for electricity during these low total system demand periods will enable an EV customer to charge his vehicle at a lower cost than if he paid a rate based on the average system cost of electricity production. This reduced EV operation expense would act to encourage EV commercialization as well as to encourage increased use of the vehicle once it is purchased. Advantages are also likely to accrue to the utility under this scenario, since increased off-peak demand will contribute additional revenues to the utility without the necessity of expanding system capacity. The difficulty here is to design a cost-effective rate structure that adequately reflects the costs of providing service without artificially discouraging the commercialization of electric vehicles. Particular care must be taken to avoid a sudden surge in electric demand that might occur if all EVs were plugged into the system at the same time.

Figure 2-1 displays representative peakday and average weekday load curves for an electric utility. This figure shows that total system demand varies over the hours of the day, with the off-peak period--the time when system demand can be met entirely with baseload generation--occurring between the hours of 11:00 p.m. to 8:00 a.m. Assume the marginal cost of supplying electricity during this period (approximately the system lambda (λ) is 10 mills per kWh, and the marginal cost of supplying energy during the peak period is 42 mills per kWh. Thus, additional demand on the system can be supplied during off-peak periods at a cost considerably less than during peak periods.[4]

If EV demand can be confined mostly to off-peak periods, and priced accordingly, the cost of operating an EV can be reduced more significantly than if an average price for electricity were charged. The problem here is the additional cost necessary to measure separately and bill the EV demand. Whether or not this can be done on a cost-effective basis depends on the nature of EV electricity demand, the load characteristics and cost structure of the specific utility company, and the cost of the necessary metering equipment and additional billing expense.[5]

[4]It should be noted that the system lambda represents only the additional "running cost" of supplying electricity. In order to determine the total cost of supplying electricity during peak and off-peak periods, the remaining costs of service need to be added. These include capacity costs, transmission and distribution costs, operation and maintenance costs, line losses, and general overhead. The system lambda shows the minimum additional cost of supplying additional load during peak and off-peak periods. If a marginal-cost-based pricing method is used and all capacity costs are assigned to the peak period, additional electricity supplied during the off-peak period would be priced very near the system lambda.

[5]A recent NRRI report contained an analysis of the cost-effectiveness of time-of-day pricing for residential customers of New York electric utility companies. Data included in the report indicated that appropriate metering equipment is available at a cost, including installation, of between \$150 and \$260 in 1978 dollars. Additional maintenance and meter reading and processing costs of \$13 to \$19 per year per meter in 1978 dollars would also be required. See: A Method to Assess the Economic Feasibility of Time-of-Day Pricing for Residential Customers (Columbus, Ohio: The National Regulatory Research Institute 1979), p. 18.

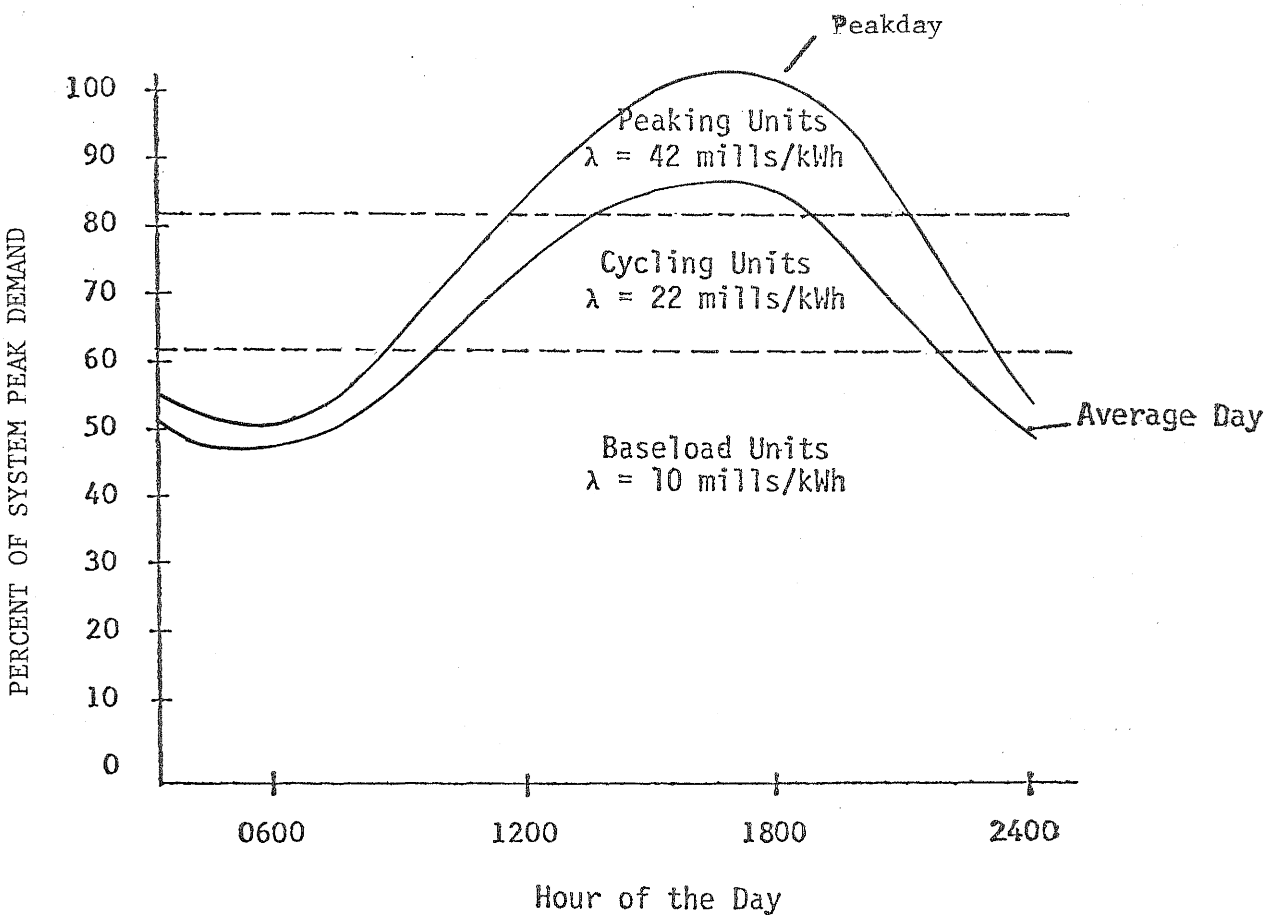


Figure 2-1 Representative peakday and average weekday load curves for an electric utility

The Nature of Electric Vehicle Demand

A number of analyses have been performed to estimate the probable market penetration of electric vehicles. These estimates are summarized in table 2-2, and range from a low of 92,000 EVs by 1983 (the Arthur D. Little estimate), to a high of 11 million to 13 million EVs by the year 2000 (Mathtech estimate).[6] Discussions with analysts for the Institute for Interdisciplinary Engineering Studies at Purdue University indicated that the SRI estimate of 1.5 million electric vehicles in operation by 1995 appears to be the best estimate for the purposes of this analysis.

While these studies estimate the probable total population of EVs for a particular year, they offer very little information on the distribution of EVs among various uses (e.g., residential versus commercial use), or on the geographic dispersion of EVs (i.e., will they be evenly dispersed throughout the country or heavily concentrated in several large urban areas?). These factors have obvious importance in determining the impact of EVs on a particular utility, since one utility company may experience no significant EV load on its system while another may have a heavy concentration of EVs within its service area.

The nature of EVs suggests the types of use and likely areas of concentration in which they will be found. With limited range (currently about 50 miles on a single charge) and speed (currently about 30 miles per hour), EVs are most likely to be used as second or third cars for residential commuting or short trips in urban areas. For commercial customers, EVs are appropriate for certain types of delivery purposes in urban areas.[7] The Arthur D. Little study referred to in table 2-2 found that EVs are most likely to be purchased by households that are already multicar and are located in warm or temperate climates. This market is

[6]"Introduction of Electric Vehicles into the Utility System: Analysis of Research Needs," Draft Final Report by Systems Control, Inc., Palo Alto, California, July 16, 1980, pp. 2-6--2-11.

[7]See: Factors Affecting the Commercialization of Electric and Hybrid Vehicles, prepared by the Institute for Interdisciplinary Engineering Studies, Purdue University, for the U.S. Department of Energy, Division of Transportation Energy Conservation, October 1978.

TABLE 2-2

ESTIMATES OF ELECTRIC VEHICLE MARKET
PENETRATION BY VARIOUS YEARS

Analyst	Market Penetration Prediction
Mathtech, Inc.	1-2 million vehicles by 1985 2-3 million vehicles by 1990 11-13 million vehicles by 2000
Stanford Research Inst. (SRI)	1-5 million vehicles by 1995
Arthur Andersen Co.	3.1-6.2 million vehicles by 1998
Arthur D. Little, Inc.	92,000-1.2 million vehicles by 1983 0.53-6.9 million vehicles by 1990

Source: Introduction of Electric Vehicles into the Utility System: Analysis of Research Needs, Draft Final Report by Systems Control, Inc., Palo Alto, California, July 16, 1980

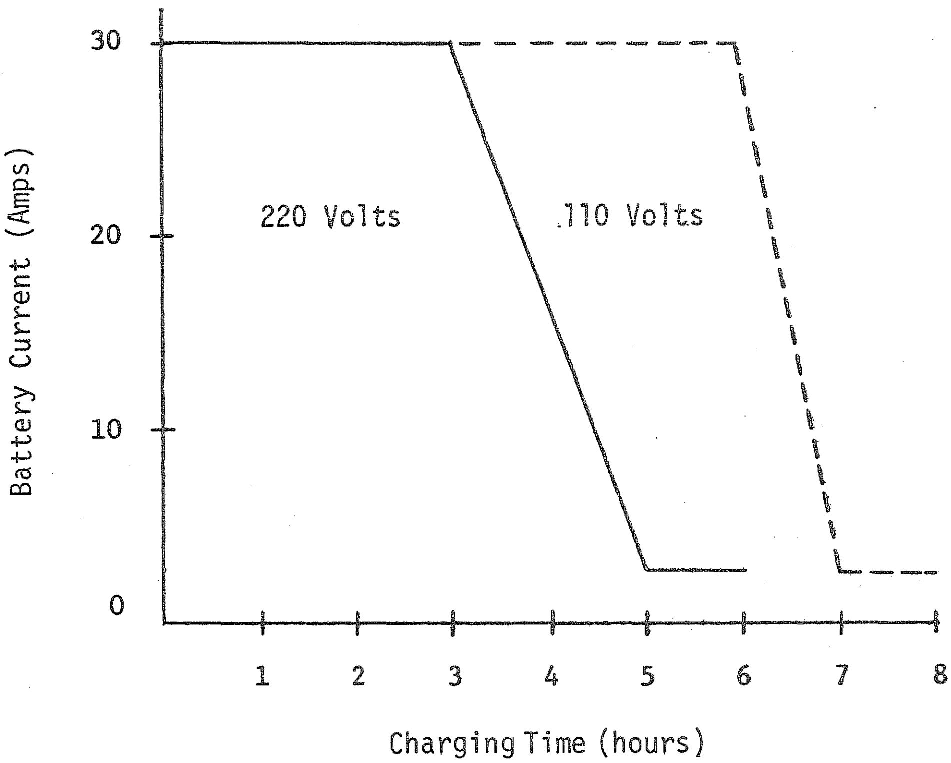
about 37 percent of the total automobile market. The Mathtech study, also referred to in table 2-2, confirms the intuitive presumption that the price of the traditional internal combustion engine vehicle has an important impact on the demand for EVs (the higher the price for ICEVs the greater the demand for EVs), as does the price of gasoline and fuel efficiency of ICEVs. Obviously, the availability of gasoline--aside from its price--will have a large impact on EV demand. If a severe shortage of petroleum products should develop, the demand for electric vehicles could increase substantially.

The almost certain development of electric vehicle demand over the next 20 to 30 years means that utilities and regulators should adequately prepare for the eventual appearance of this load on electric utility systems. However, while the development of EV demand in general appears certain, the specific nature of that demand is not. This represents a major difficulty for electric utilities and their regulators in adequately preparing to meet this expected load. Additional analysis in this area, and electric utility and regulatory commission awareness of, and involvement in, EV commercialization would seem a prudent next step. Only then can the impact of EV load on the cost characteristics of particular electric utilities be properly estimated and appropriately priced. There are, however, certain pricing methods that can be employed in the short run to help assure that the commercialization of EVs is not artificially impeded, pending further detailed analysis of load characteristics.

As with all other types of service, the prices paid for charging EVs should be based primarily on the cost of providing service. This principle allows each type of service to stand on its own merit and keeps to a minimum the amount of cross-subsidies among various categories of electric service. Since a substantial EV load is not likely to occur for several years, utilities are unlikely to move to create a separate customer class or rate category for electric vehicles. However, by ignoring the possible effects of EVs on the systems' cost characteristics, utilities may be missing an opportunity to determine, at least partially, the nature of EV load development to the benefit of both themselves and their customers.

The expected systematic nature of EV use--daily commuting, local shopping trips, daily commercial delivery routes--implies that they will be plugged into the system for recharging primarily during evening and night off-peak hours. For this reason, EVs are a potentially important load management device that could contribute to improved utility system load patterns and revenue stability. If left to develop on its own without electric utility and regulatory commission involvement, EV load may evolve in a haphazard way that minimizes the possibility of achieving any substantial load management benefits.

Rather than creating a separate customer class, electric utilities could simply offer EV customers a type of interruptible or off-peak rate similar to that currently offered for residential electric water heating. This service would allow EV charging only during specified off-peak periods, in exchange for which the customer receives a reduced rate. (If priced according to marginal cost concepts, the rate for off-peak consumption would be only slightly above the marginal running cost for that period and would offer a substantial discount from peak-period prices. However, metering costs must be considered.) Here is where the load characteristics of the utility and the EV become particularly important. It typcally takes 6 to 8 hours to charge an EV, with the battery initially drawing a large current that drops off significantly as the battery becomes charged. (See figure 2-2.) Occasionally, the battery must be charged to a slightly "overcharged" condition to ensure adequate performance and usefulness of the battery. This procedure may take up to 16 hours, although the amount of electric current drawn by the battery over the second 8 hour period is relatively small. If the utility's off-peak period is not long enough to allow full battery charging to take place, some portion of EV electricity consumption would take place during higher cost hours. These higher costs should be reflected in the rates charged to EV customers. The length of time needed to charge the batteries of EVs and the length of time of electric utility system off-peak hours are critical determinants of the load management capability of EVs. Of course, if battery technology improves so that the length of time necessary to charge an EV is shortened, the magnitude of this problem may be reduced or eliminated.



Source: Institute for Interdisciplinary Engineering Studies, op. cit., p. 61.

Figure 2-2 Typical charging time and amperage requirements for an electric vehicle

CHAPTER 3

ELECTRIC UTILITY LOAD CHARACTERISTICS AND REVENUE REQUIREMENTS

This section contains an analysis of the probable impact of electric vehicles on a typical electric utility system's load characteristics and revenue requirements. An analysis of the likely effect of various utility rate structures on the pricing of electric service provided to EVs is also presented.

Table 3-1 shows illustrative capacity and electric energy requirements for a stock of electric vehicles. This information was derived from estimates of the Systems Control, Inc., study referred to earlier and represents actual EV battery requirements and usage patterns based on present technology. The total annual electric energy consumption of 2,372.5 gWh (gigawatt-hours) represents approximately 4 to 5 percent of total energy sales of a typical 10,000 MW (megawatt) electric utility (assuming a 50 percent load factor). The total capacity requirement of the electric vehicles, 814 MW, represents about 8 percent of total capacity requirements, excluding reserve requirements. The critical factor here is the timing of the EV load. If all the vehicles were to be charged during off-peak periods--assuming the utility had sufficient baseload capacity available to meet this load--the energy requirement could be supplied at a low, off-peak rate because no additional capacity requirement would be placed on the system. From the data contained in figure 2-1, this energy requirement could be supplied at a price just slightly above 1.0 cent per kWh (to account for line losses and some general expenses, and excluding metering costs). Based on total EV energy requirements of 2,372.5 gWh,

TABLE 3-1

ILLUSTRATIVE CAPACITY AND ELECTRIC ENERGY
REQUIREMENTS FOR A FLEET OF ELECTRIC VEHICLES

Number of Passenger EVs (PEVs)	0.2 million
Number of Commercial EVs (CEVs)	0.02 million
Energy from Battery of PEV	0.50 kWh/mile
Energy from Battery of CEV	1.50 kWh/mile
Average Daily Energy into Battery Required by PEV*	25.0 kWh/day
Average Daily Energy into Battery Required by CEV*	75.0 kWh/day
Power Drawn by PEV during Charge**	3.13 kW
Power Drawn by CEV during Charge**	9.38 kW
Yearly Energy Required by PEV Stock	1,825.0 gWh
Yearly Energy Required by CEV Stock	547.5 gWh
Total Yearly Energy Required	2,372.5 gWh
PEV Power Drawn, Assuming Simultaneous Charging	625.0 MW
CEV Power Drawn, Assuming Simultaneous Charging	188.0 MW
Total Power Drawn	814.0 MW

* Corresponds to 40 miles/day, 0.8 battery efficiency
** Corresponds to a constant charge for 8 hours

Source: Introduction of Electric Vehicles Into the Utility System: Analysis of Research Needs, prepared by Systems Control, Inc., Palo Alto, California, Draft Final Report, July 16, 1980, table 3-4a, pp. 3-14.

this would represent approximately $23.8 million in revenues to the utility and an electric energy cost of about 0.6 cents per mile for the PEVs and 1.9 cents per mile for the CEVs.

If all of the EVs were charged during peak periods, the cost of supplying energy would increase dramatically, since the utility would need to recover its demand-related capacity and transmission and distribution costs. This type of demand pattern could also place the utility in a position where it would need to expand its generating capacity and transmission and distribution system in order to meet the additional demand while maintaining the same level of system reliability. Also, since peaking capacity uses more costly fuel than does baseload capacity, the fuel cost of supplying this new load would also increase substantially.

Again referring to the sample costs in figure 2-1, the marginal running cost of supplying peak demand is 4.2 cents per kWh. Assuming a doubling of this figure to cover capacity and T&D costs, line losses, general expenses (including profit), and customer costs but excluding any additional metering costs, energy could be supplied to the EV load at 8.4 cents per kWh. This would represent approximately $199.3 million in revenues to the utility at an electric energy cost of about 5.0 cents per mile for the PEVs and 15.9 cents per mile for the CEVs.

Electric Utility Loads and Fuel Mix

As noted above, each electric utility designs its system to meet its load characteristics. This results in a "mix" of generating facilities intended to supply power at minimum cost, given a set of load requirements. In addition to a mix of generating facilities, each utility also employs some combination or mix of fuels to operate those facilities. As mentioned earlier, new baseload plants are generally coal-fired or nuclear-fueled facilities, although a considerable amount of oil-fired baseload generation is currently in operation, especially in the Northeast and Southeast and in California. Intermediate or cycling plants are predominately coal-fired or oil-fired facilities, and the smaller peaking units are fueled almost entirely by oil or natural gas.

If electric vehicles are to replace a substantial portion of petroleum use in the transportation sector of the economy, the type of fuel used to generate the electricity used by EVs is critical. This fuel type in turn is critically dependent on the timing of the EV load on the utility system. If EVs are charged during off-peak times, sufficient coal-and nuclear-generating capacity will be available in most cases to supply the EV demand. If, however, EVs are charged primarily during peaktimes, much of the additional electricity produced to meet the EV requirements will be supplied by oil-fired generation. This situation will negate one of the primary reasons for introducing EVs as an alternative to the internal combustion engine vehicle--petroleum conservation. Thus, the timing of EV demand on the utility system is important in achieving a reasonable level of petroleum conservation. Off-peak charging of EV batteries will allow maximum substitution of alternative energy supplies for oil consumption in the transportation sector, as well as provide the lowest cost electricity available for this purpose.

Electric Utility Rates and Revenues

As noted above, electric utility rate structures should reflect the actual costs of providing service. Due to the varying nature of demand on the system, these costs vary by time of day and season of the year. In many cases, however, time-of-day rates are not cost-effective for a utility's residential and small commercial customers. As a result, residential and small commercial customers' (also known as general service customers) rate structures are being altered in various ways to reflect more accurately the costs of providing service without requiring new, costly metering equipment. The methods employed include "flattening" of rate structures (reducing the number of individually priced declining blocks within the rate structure), "inverted" rate structures (unit price increases with increased levels of consumption), and including a seasonal price variation in the rate (higher price per kWh during peak demand months).

EV-derived demand for electricity is a developing new load that would be added on top of current electricity demand, i.e., it would be in addition to current consumption levels. As such, EV electric consumption will increase the total kWh consumption of EV customers; the marginal impact of EV demand on the system, then, is to raise individual customer monthly consumption to higher usage levels. These levels of consumption have traditionally been priced at the lowest unit cost under the declining block rate structure. Some current pricing methodology, however, tends to raise the price of these "tail blocks" of consumption so as to recover their total cost of production and discourage wasteful use of electricity.

Table 3-2 shows illustrative electric utility tariffs for residential customers, on both a traditional, nontime-differentiated basis and on a time-of-use basis. These tariffs were derived from rate schedules of a major midwestern utility as filed with a state public utility commission. The utility has a summer peak but also has a substantial winter heating demand. Although each utility is fairly unique in regard to its load and operating characteristics, the illustrative tariffs contained in table 3-2 are fairly "typical" of the electric utility industry in general.

The first tariff shown in table 3-2 is a declining block rate. The number of "blocks" in the pricing schedule, however, have been reduced to two in order to reflect the costs of providing electric service more accurately. The customer charge represents those costs necessary to provide service to the customer that do not vary with electric consumption. The energy charge reflects demand-related and energy-related costs that vary with the total energy consumption of the customer. The higher priced initial block of service provides some revenue stability to the utility in that it allows the company to recover a greater portion of its production costs at the lower levels of consumption. This type of tariff, however, tends to underprice electricity during peak hours when costs are low. The

TABLE 3-2

ILLUSTRATIVE EXAMPLES OF ELECTRIC
UTILITY RATE STRUCTURES

I Non-Time-of-Use Rate Structures

(a) Residential Electric Service Rate--Declining Block

Customer Charge per Month:	$7.00
Energy Charges:	
First 750 kWh/Month/kWh	$0.0415
All over 750 kWh/Month/kWh	0.0265

(b) Residential Electric Service Rate--Seasonal Price Differential

	Summer	Winter
Customer Charge per Month:	$7.00	$7.00
Energy Charges:		
First 750 kWh/Month/kWh	$0.0415	$0.0415
All over 750 kWh/Month/kWh	0.0265	0.0215

Summer service is that included during the billing months of June, July, August, September, and October each year. Winter service is that included during all other months of the year.

II Time-of-Use Rate Structure

(a) Residential Electric Service Rate--Time-of-Use

Customer Charge per Month: $7.35

	Summer	Base	Winter
Energy Charge:			
OnPeak:			
First 325 kWh/Month/kWh	$0.0815	0.0580	0.0815
All over 325 kWh/Month/kWh	0.0815	0.0580	0.0490
Off-Peak:			
All kWh/Month/kWh	0.0097	0.0097	0.0097

On-Peak Periods:

On-peak periods shall be applicable Monday through Friday as follows:

Summer months--11:00a.m. through 9:00 p.m.
Base months--7:00 a.m. through 9:00 p.m.
Winter months--7:00 a.m. through 9:00 p.m.

Off-Peak Periods:

Off-peak periods shall be those periods not designated as on-peak periods.

Summer, Base, and Winter Months:

Summer months--June, July, and August
Base months--March, April, May, September, October, and November
Winter months--January, February, and December

Source: Derived from rates filed by Dayton Power and Light Company with the Ohio Public Utilities Commission customer then has no incentive to reduce his consumption during peak hours or to increase his consumption during off-peak hours. Under this rate schedule, once the initial 750 kWh of electricity was consumed, an EV customer would pay the same rate to charge his EV no matter what time of day or season of the year he chose to plug it in.

The second rate schedule listed in the table is also nontime differentiated, but it does offer a seasonal price variation. The second block of service during the off-peak winter months is priced lower than that during the peak-period summer months. Here, to the degree that his consumption is transferable, the customer has some incentive to consume less electricity during the summer and more during the winter. This rate schedule might be termed more "price efficient" than the previous schedule in that its prices more accurately reflect the actual costs of providing service.

The third rate schedule in table 3-2 is a time-of-use rate in that prices vary both by time of day and season of the year. Use of this rate schedule would require additional metering equipment for residential and small commercial customers in order to measure consumption on a time-of-use basis. This rate has three pricing periods: a summer on-peak period, a base off-peak period, and a winter "shoulder-peak" period when the demand on the system is in between that of the other two pricing periods. The months contained in each pricing period are defined at the end of the table.

The energy charges are designed to reflect the higher costs of service experienced during peak consumption hours. A flat pricing format is used during peak hours of the summer and base periods. A two-step, declining block format is used for the winter period in order to reflect the usage patterns of electric heating customers. A single rate is charged for all energy consumption during off-peak hours in order to reflect the lower costs of service during these times. The hours of peak-period consumption for the three pricing periods are listed at the end of the table.

Table 3-3 translates these tariffs into monthly bills based on 1000 kWh per month for residential consumption without EV usage and 1,750 kWh per month with EV usage. (The 750 kWh average use per month for the EV was derived from data in table 3-1: 25 kWh/day x 30 days/month.) The total monthly bill for the declining block rate increases from $44.76 to $64.63 with EV usage. The total monthly bills for the seasonal rate schedule show similar increases, although the lower off-peak winter rates provide some reduction in bills for those months. This seasonal price differential, however, will have little if any affect on EV use, since the number of hours of operation of EVs are generally not transferable from one month to another.

The residential time-of-use rate, however, provides a substantial price incentive to the residential customer to charge his EV during off-peak hours. The time-of-use rates section of table 3-3 shows the total monthly bill of a residential customer without an EV for the three pricing periods, assuming 50 percent of total consumption occurs during peak hours. These bills range from $41.20 in the base period to $48.89 in the winter period and $52.95 in summer for 1,000 kWh consumption during each period. The table then shows total monthly bills for the same customer with an EV for the three pricing periods, again assuming 50 percent of total kWh consumption takes place during peak hours. Total on-peak energy consumption, then, has risen from 500 kWh to 875 kWh, with the difference (375 kWh) representing that portion of total EV usage that takes place during peak hours. The total monthly bills for the three pricing periods under this usage pattern are $66.59 for the base period, $70.90 for winter, and $87.15 for summer.

Table 3-3 next shows total monthly bills for the three pricing periods for a residential customer with an EV, this time assuming that all EV usage takes place during off-peak hours. Total monthly bills under this scenario are $48.48 for the base period, $56.17 for the winter period, and $60.23 for the summer period. These figures show that by confining all EV charging to off-peak periods (as opposed to 50 percent of charging during peak hours), the residential customer can significantly reduce his total monthly electric bills during all three pricing periods.

TABLE 3-3

TYPICAL MONTHLY ELECTRIC BILLS FOR RESIDENTIAL CUSTOMERS
WITH AND WITHOUT ELECTRIC VEHICLES

I. Non-Time-Of-Use Rates

	(a) Declining Block Rate		(b) Seasonal Rate			
	Without EV	With EV	Without EV		With EV	
Total Monthly kWh Consumption:	1,000	1,750	1,000		1,750	
Customer Charge:	$7.00	$7.00	$7.00		$7.00	
Energy Charges: ($)						
First 750 kWh	31.13	31.13	31.13	31.13	31.13	31.13
All over 750 kWh	6.63	26.50	6.63	5.38	26.50	21.50
Total Monthly Bill ($)	44.76	64.63	44.76	43.51	64.63	59.63
Average Cost per kWh ($)	0.0448	0.037	0.0448	0.0435	0.037	0.0341
Incremental Cost of Energy Use per kWh ($)	0.0265	0.0265	0.0265	0.0215	0.0265	0.0215

TABLE 3-3 (Cont'd.)

II. Time-Of-Use Rates

	(a) Without EV (50% usage on peak)			(b) With EV (50% usage on peak)			(c) With EV (All EV usage off peak)		
Total Monthly Consumption:	1,000 kWh			1,750 kWh			1,750 kWh		
Customer Charge: ($)	7.35			7.35			7.35		
Energy Charge: ($)	Summer	Base	Winter	Summer	Base	Winter	Summer	Base	Winter
On peak									
First 375 kWh	30.56	21.75	30.56	30.56	21.75	30.56	30.56	21.75	30.56
All over 375 kWh	10.19	7.25	6.13	40.75	29.00	24.50	10.19	7.25	6.13
Off peak	4.85	4.85	4.85	8.49	8.49	8.49	12.13	12.13	12.13
Total Monthly Bill ($)	52.95	41.20	48.89	87.15	66.59	70.90	60.23	48.48	56.17
Average Cost per kWh ($)	0.053	0.0412	0.049	0.050	0.038	0.041	0.0344	0.0277	0.0321
Incremental Cost of Energy Use per kWh ($)	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097
Total Monthly Bill ($)									
II(b)	87.15	66.59	70.90						
II(c)	60.23	48.48	56.17						
Total Difference per Month ($)	26.92	18.11	14.73						
Total Annual Difference ($)	233.61								

Source: Computations based on data contained in previous tables

Table 3-3 presents a summary of these cost differences. At the bottom of the table, the total monthly bills under option II(b) when 50 percent of EV usage takes place during peak hours are listed for the three pricing periods. The total monthly bills for option II(c) where all EV usage occurs during off-peak hours are also listed for each pricing period. The difference between the total monthly bills for these two usage patterns is shown as $18.11 for the base period, $14.73 for the winter period, and $26.92 for the summer period. By multiplying each of these price differentials by the number of months in each pricing period, we may derive the total annual difference in cost of EV usage between the two usage patterns. This difference is shown to be $233.61.

This figure has considerable significance to the EV customer and to the utility. It shows that the EV customer can substantially reduce his total monthly electric bill and his cost per mile of operating the EV if time-of-day pricing is available and if he takes advantage of low off-peak electric rates. The utility company may also benefit from an improved system load factor that results in increased kWh sales without the necessity of plant expansion. This total annual cost savings also indicates that it would be beneficial both to the utility and the EV customer to install necessary metering equipment to measure separately off-peak energy consumption if the annual cost of that equipment is less than, or equal to, the annual cost savings.

CHAPTER 4

ELECTRIC UTILITY AND REGULATORY COMMISSION INVOLVEMENT IN EV COMMERCIALIZATION

As mentioned earlier, in exchange for their franchised monopoly position, electric utility companies must offer service to all customers within their service territory. Therefore, when an EV load develops within a utility's service territory, it must serve that load at a "just and reasonable" rate. However, utility companies and state regulatory commissions have a lot of discretion on how that load is served. They may simply take a "business as usual" approach and deal with the EV load when and where it develops, or take a more farsighted approach and address the developing EV load to determine how and if it fits in with other demands on the utility's system.

If the number of EVs introduced into a service territory is small, the impact on the utility will also be small. The utilty may find it not to be worth its while to prepare actively for or to encourage EV commercialization. Also, the utility may enjoy a relatively high or even load factor and therefore not experience sufficiently long off-peak periods that enable it to offer discount prices for EV charging. On the other hand, a utility and its regulators may see the developing EV load as a means of improving a poor load factor and an opportunity to achieve long-term benefits to the utility and its customers.

We have seen in the previous chapter that there may be an opportunity for utilities to use EV demand as a load management technique, a procedure encouraged by recent federal law (PURPA). The "just and reasonable" and "not unduly discriminatory" rate-setting requirements of regulatory practice imply that utilities and their commissions cannot simply ignore the development of a new and potentially beneficial load within the utility system. They must offer rates for this service on a cost-justified basis. The question is not if utilities and state regulators will become involved in the commercialization process of EVs, but what the nature and degree of that involvement will be.

Utility commissions may view participation in the commercialization of EVs as beyond the scope of their regulatory mandate, leaving it up to manufacturers of EVs and utility companies to work it out. Other commissions may see potential load management advantages to EV commercialization and encourage electric utilities within their jurisdiction to participate actively in the commercialization process. Certainly, all regulatory commissions must at least deal with the pricing problem and ensure that electric utility service is offered to EV customers at fair, cost-based rates.

Utility companies may see EV commercialization as a potentially profitable sideline to their main function of producing and distributing electric power. Besides certifying the adequacy and safety of EV chargers installed on a customer's premises, utility companies may seek to become involved in leasing and/or servicing electric vehicles or offering "charging centers" where customers could recharge their vehicles at times and places other than in their own homes. Utilities may see these, and other, interventions into the electric vehicle market as a means of managing or more evenly distributing EV load so as to minimize the impact on the utility system and take maximum advantage of any benefits derived from EV demand. Any involvement of electric utilities in EV commercialization would necessarily require regulatory oversight and review.

Electric utility companies have a long history of involvement in areas of business related to, but not directly involved in, the process of providing electric service to their customers. For a number of years, utility companies provided sales and service of electric appliances to customers within their service territory. Utilities were also involved in encouraging the use of electric heat and promoted the concept of the "all electric" home.

Beginning primarily in the 1960s, much of this involvement came to an end. Regulators became concerned with the problems of effectively regulating a company that was involved in both a regulated and unregulated market. The separation of costs and revenues between those activities of a company that are regulated and those that are not presents a particularly difficult problem. Also, a utility may spend an inordinate amount of time and resources promoting its unregulated market activities to the detriment of its regulated activities where public utility commissions have a degree of control over utility expenses and profits.

With the advent of rising energy prices and developing shortages of energy supplies, it became difficult for utilities to justify their nonregulated business activities that tended to encourage energy consumption. Over the last decade or so, commissions have begun to disallow promotional advertising expense as a cost-of-service item. To this end, Section 113(b)(5) of PURPA prohibits electric utilities from recovering promotional advertising expense from its ratepayers. While a number of utilities are still involved in sales and/or service of electric appliances, the number of companies doing so has declined substantially. Rather than eliminating their involvement in unregulated activities, however, electric utilities have shifted the emphasis of that involvement from one of encouraging energy consumption to one of promoting energy conservation.

Electric utilities throughout the country are involved in various types of weatherization programs. Under these programs, utilities may recommend and install energy conservation measures in a customer's home. These measures range from weather stripping and home insulation to new furnace burners and other devices designed to decrease energy consumption within the home. It should be noted that in some instances the degree of utility involvement in these programs is limited. For example, the National Energy Conservation Policy Act, PL 95-619, prohibits utilities from installing energy conservation measures in customer residences unless the utility had already been involved in such a program prior to enactment of the act. Utilities may also be subject to various local restrictions largely dependent upon historic precedence and the orientation of the state public utility commission.

Electric utility involvement in EV commercialization would encompass many of these same issues. State regulatory commissions may prohibit utilities from becoming actively involved in promoting EVs and from offering associated services such as sales, servicing, and leasing of electric vehicles. There is some increasing level of recognition, however, among both federal and state regulators that electric utility company participation in programs designed to achieve various energy policy goals might be more beneficial to all those involved if the companies could share in the benefits derived from these programs. Therefore, utility company involvement in EV commercialization, in terms of providing associated sales and services, might be an effective way of encouraging petroleum conservation through the expanded use of electric vehicles.

CHAPTER 5

INCENTIVES AND DISINCENTIVES FOR ELECTRIC UTILITIES

Incentives and disincentives for utilities to promote, impede, or remain neutral on the use of electric vehicles arise from a combination of (1) societywide economic currents and (2) special considerations introduced by public utility regulation. Emphasis herein is given to regulation. Long-term economic phenomena such as increasing fuel costs and a continuing inflation problem are treated in the context of regulation.

Were electric utilities not "natural monopolies," growth of EVs could be analyzed in a simple supply-demand context. The monopolistic character of electric utilities, however, brings regulation, and with it, a range of public policies that mold and constrain business decision making. Resulting incentives and disincentives are analyzed herein.

The pattern of analysis is to consider a limited number of specific topics and within these, incentives and disincentives as relevant. The time frame is the next two decades. It is during this period that EVs are likely to become an important part of (intraurban) transportation systems. Necessarily, consideration is given only to broad, long-standing characteristics of regulation, such as are likely to prevail over the two-decade time horizon.

Plant Capacity and Earnings

Available plant capacity determines the extent to which additional costs must be incurred to furnish increased output. The electric power industry has experienced a fairly high level of excess (or reserve) capacity over the past 20 years. The greater the excess capacity, the more incentive there is for electric utilities to promote load growth, including EVs.

In the late 1960s average capacity factors for the nation as a whole were about 54 percent, i.e., 54 percent of full-time full-rated output was produced. Capacity factors dropped to about 45 percent by the mid-1970s. At the same time, average gross peak margins increased sharply. The percentage by which total capacity exceeds peak demand increased from 18 percent in the late 1960s to over 33 percent in the mid-1970s. Traditionally, 20 percent has been considered adequate as a safety margin. There has been some decline in reserve capacity over the last several years particularly for some individual systems as construction of new generating facilities has either been delayed or canceled. Available capacity to meet system requirements, however, is expected to be adequate over the next 20 years, especially since load growth has declined significantly since the 1973-74 oil embargo and is expected to remain at a low level in the future. The potential for EV-induced load management, therefore, should not be overlooked.

A partial explanation for this increasing reserve margin is found in a number of financial practices adopted over the last 20 years, plus some more recent inflation remedies introduced into state utility regulation.

The situation is illustrated by accelerated depreciation (in a regulatory environment). In some states, electric power rates are based on straight line depreciation, but corporate income taxes are based on accelerated depreciation. The younger the average plant in a utility system (and hence the more rapid the rate of growth) the greater the favorable effect on retained earnings. The opposite, of course, occurs with slow growth or no growth. Indeed, it is quite possible for calculations as described above to produce negative earnings late in a plant's life. Thus, the result is to create a dynamic incentive in which growth, once started, must be maintained if earnings are to hold their established level.

Some other financial aids associated with utility investments have a tendency to work in the same way. Among these is the investment tax credit, and in the case of a number of state regulatory commissions, the inclusion of construction work in progress (CWIP) in the rate base. This last practice has grown especially as a result of inflationary pressures. There are other regulatory remedies to inflationary pressures, such as expedited hearings and the "pancaking" of rate cases.

The effect of today's inflation on tomorrow's capacity remains to be seen. Utilities are somewhat insulated from financial disruption, as noted above, but adverse effects of inflation on capital formation cannot be ruled out.

On the other hand, there has been a distinct slowing of load growth in recent years. Electric power demand grew at 6 to 7 percent in the 1950s and 1960s. The projected growth of electric power is closer to 4 percent in the 1980s and 1990s. (Total energy growth will be even less, at an annual average of 2 percent.) Any slowing of capacity growth will have to more than match this projected load growth decline if reserve margins are to decline.

There are two other aspects of regulation that could slow electric utility expansion in the next two decades. The first is state siting restrictions. In a few "strong" regulatory states, such as California, these can act to retard capacity growth. The second aspect is the pursuit of cost-of-service over value-of-service ratemaking.

The choice between cost-of-service and value-of-service regulation has two kinds of effects on EVs. In the present context, the issue has to do with earnings and expansion. <u>Insofar as expansion alone is concerned</u>, the utilities are more likely to promote EVs with value-of-service ratemaking. <u>However insofar as rates charged for EV power are concerned</u>, the results could go either way, depending on the time horizon of ratemaking, as described below.

To conclude the discussion of excess capacity and earnings, there is a strong incentive today to promote load growth. This incentive arises from excess capacity. Looking to the future, it seems likely, on balance, that excess capacity is not likely to decrease much, if at all, as a percentage of total capacity.

Value-of-Service and Cost-of-Service Ratemaking

Value-of-service ratemaking consists of setting rates according to willingness to pay, which in turn, is reflected in consumer demand. Consumers having low elasticities of demand (low-percentage decline in demand relative to percentage increase in price) are charged higher rates, and those with high elasticities of demand (high-percentage decline in demand with a given percentage increase in price) pay lower prices. The reason, of course, is that the former consumers are less sensitive to price increases than the latter, and more revenue is received by treating them differently. Some contend that declining block rates, wherein additional quantities cost the same consumer lower prices as he expands consumption, are a form of value-of-service pricing. Since demand curves are negatively sloped, larger amounts of revenue are received by charging higher prices for the early blocks and less for the tail blocks, as compared with a uniform rate (or prices) for any given amount consumed.

As noted earlier, however, this form of pricing tends to underprice electricity during peak periods and overprice it during off-peak periods. Thus while value-of-service pricing may encourage energy consumption it may also lead to revenue deficiency for the utility if the additional consumption takes place during periods of peak demand. This condition has been a force behind the current move away from value-of-service pricing.

Value-of-service pricing may be advantageous to any seller but generally cannot be achieved in competitive markets. It can be, and is, achieved in regulated markets. The advantage to value-of-service pricing for regulated companies is that it helps to finance expansion. Over and above the forces for expansion described above, is the traditional "fair return on fair value" floor on earnings. Investments, as long as they can be justified, are entitled to a "fair return on fair value." More investments can be justified with value-of-service ratemaking then with cost-of-service ratemaking because the former tends to promote electric consumption. This expanded consumption necessitates expansion of capacity. Once this capacity is included in the utility's rate base, additional revenues are needed to support it.

Value-of-service ratemaking is likely to treat EVs as a separate demand, that is, with separate rate schedules. In the introductory EV years, and throughout a transition from fluid-fueled to electric-powered vehicles, demand will be relatively elastic, most so in the early stages. Electric power sellers will be interested in attracting owners of new EV's, who are concerned with lifetime (of the vehicle) costs. Electric power sales will be more influenced by the number of vehicles than by the electricity consumed per vehicle.

In the later stages, when the market is near saturation, demand will become highly inelastic if the information currently available on gasoline consumption is any indication. Under value-of-service pricing, the result in later stages will then be higher rates, assuming of course, that commissions allow this type of pricing.

Declining block rates are often considered as one form of value-of-service pricing. Such rates tend to encourage consumption, as noted above. However, declining block rates also would have another effect on EVs. They would discourage charging at different locations. The EV consumer who did all of this charging on one meter would get a lower average rate, other things being equal, than his neighbor who might charge some at home and some elsewhere. This phenomenon is important, as we shall see below, in determining the extent to which competition might be introduced into EVs' power supply.

Cost-of-service ratemaking is the opposite of value-of-service ratemaking in that emphasis is on supply rather than on demand conditions. A number of steps are taken in the Public Utility Regulatory Policies Act of 1978 to move public utility regulation more toward cost of service. Time-of-use pricing, using either average or marginal costs, is strongly encouraged; and declining block pricing is discouraged. These provisions are not mandatory for state commissions, but if serious problems arise in present efforts at rate reform, binding statutory guidelines may come later.

Cost of service has long been a part of traditional rate structures in the form of lower rates offered by many utilities for electric hot water heaters, presumably because their use is greatest during off-peak hours. Exactly the same kind of service would seem natural for electric vehicles, particularly in view of the importance attached to time-of-day rates in current policy. In addition, whether there is a separate rate schedule or not for EVs, time-of-day rates would, by their nature, make lower rates available at off-peak times. Commercial customers with predictable vehicle use on a daily cycle would best be able to take advantage of a regular off-peak schedule. Many residential customers might also be able to adjust their use patterns so as to confine recharging time to off-peak hours. Both commercial and residential rate schedules could be adapted for off-peak rates, though with some additional expense in metering devices. If necessary, load management might be imposed through the regulation of load limits and charging times if these techniques are compatible with EV-charging requirements. It is conceivable that interruptible power might also be used for charging EVs, but interruptibility is more a character of peak than off-peak periods.

A special consideration in the pricing of electric power for EVs is road-use taxes. Automobiles operated with fluid fuel pay road-use taxes in the price of the fuel. EVs use the roads but would not pay a road tax unless it were added to electric power rates or charged to the owner in some other way such as a license fee. However, since the road tax is currently applied to vehicle operation in relation to the number of miles driven by including the tax in the price of gasoline, a license fee may not be an appropriate way to collect this tax. It would be relatively easy to add this tax onto the price charged for EV electricity consumption if this consumption were separately metered. It might also be appropriate to allow a differential between taxes for road use for fluid fuel vehicles and those for electric-powered vehicles to reflect the greater social costs of the former in terms of noise and air pollution.

Still another kind of tax might be called for by society. This is the "congestion toll." Whether congestion tolls might be different for fluid fuel engines and EVs depends on how the two kinds of vehicles are managed in high-density areas. It might be feasible, for example to provide for central control of EVs if they were operated directly from a "third rail,"as in rapid transit, to which EVs could be attached at selected points. Electric power used in this way would more likely be on peak, but higher electric power rates for this purpose might be more than offset by exception from a congestion toll as a condition of participation in the central control system.

Competing Power Sources

Probably the most important disincentive for electric utilities arises from the ability of EVs to buy power from competing sources. Two such sources come to mind.

Downtown parking garages might offer vehicle-charging services, which in some circumstances, could be convenient and competitive with home charging. Thus, downtown workers who park all day might find it convenient to plug in while at work. They might find it worth the cost to buy on-peak power if they were heavy consumers of electric-powered transportation or if, for some reason, overnight charging was inconvenient.

There is, of course, no need for downtown garages to be in the service area of the utility that supplies power for overnight charging. The possibility of interutility competition should not be overlooked. Indeed, the downtown garage, whether publicly or privately owned, might get its electricity from a municipal power plant, and the muncipal utility might very well wish to offer rates that compete with those offered by suburban utilities. Many municipal plants were originally designed for night lighting. This would be one way for such a utility to increase its daytime load, assuming that other opportunities have been denied it.

An additional factor to consider here is whether or not the parking garage would be viewed as a "public utility" and therefore subject to regulation once it began to offer electric service to its customers. Of course the municipal utility may offer this service itself by installing EV chargers in parking areas and allowing commuters to recharge their batteries while at work. The cost of this service could be charged to the customers' residence, particularly if the same utility served both locations, or separate billing could be arranged; some type of credit card mechanism to handle billing requirements is not hard to imagine.

Of course, the suburban utility, or the same utility serving both municipal and suburban locations, could offer this same service at shopping centers or nonmunicipal parking lots.

Still another interesting possibility arises from congenerated electricity. If electric utilities are reluctant to buy congenerated power from an industrial concern, the latter might find a way to offer it to a downtown parking garage. Failing this, or by first choice, the congenerator could sell to its own employees while they are at work, with a charging system in the company parking lot. The possibilities work not only to the advantage of electric vehicles but also to the advantage of society insofar as congeneration is encouraged and competition is introduced into electric power pricing.

More broadly, electric utilities have special status as regulated monopolies because it is generally presumed that competition is unworkable. One of the reasons for this presumption is the necessity for physical interconnection between electricity buyer and seller. With EVs, the consumer is mobile. Connections do not have to be with only one supplier. Consumers can shop about for low priced power, whether from another utility or from a source outside the electric utility industry.

Vehicle Sales and Leasing

As previously mentioned, electric utilities have long been involved in the sale of appliances, and communications utilities have a long established tradition of leasing or renting telephonic equipment. Regulatory commissions customarily approve both sales and leasing. Electric utilities would have the incentive to engage in both of these, plus related maintenance, on the usual ground that such would help in load building, and insofar as leasing is concerned, would afford some control over source of power used by lessors.

Summary

Incentives and disincentives should be distinguished from the question of what utilities actually will do. Discussion herein is limited to the former, as related to electric vehicles. In practice, electric utilities will take account of incentives and disincentives in the context of public relations, strategy in dealing with regulatory commissions, perceived self interest, and many other such considerations.

Incentives to support the growth of EVs are probably stronger than disincentives. Incentives arise from the natural interest of utilities in load building. This interest is all the stronger because of the condition of excess capacity and probable continuation of excess capacity into the future.

Value-of-service ratemaking is being qualified with cost-of-service ratemaking, but either way, rates should generally be favorable to electric vehicles in the foreseeable future. With value of service, promotional rates would seem to fit the historic response of electric utilities to significant new appliance demands. With cost of service, off-peak rates would again be favorable.