Final Report on

MARGINAL COST RATEMAKING FOR COGENERATION, INTERRUPTIBLE, AND BACK-UP SERVICES

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EXECUTIVE SUMMARY

Recent developments in federal law and regulatory rulings have required state public utility commissions (PUCs) to re-examine the electric pricing policies and rate structures of electric utilities. Among other requirements, PUCs must consider the appropriateness of pricing electricity on the basis of its marginal cost. This report explores the application of marginal cost pricing principles to three special electric ratemaking areas: cogeneration rates, interruptible rates, and the setting of rates for back-up power.

With respect to cogeneration purchases, FERC rules generally require that rates equal the utility's avoided cost. Calculation of avoided cost is equivalent to calculation of some type of utility marginal cost. The relevant marginal cost depends on whether the utility avoids energy costs only or avoids additional capacity costs as well.

Two classes of interruptible service are here proposed, one with a minimum target reliability (Class I) and the other without (Class II). The objective is to avoid the extremes of either subsidizing nominally interruptible customers who in practice are rarely interrupted or requiring all interruptible customers to accept a high frequency and extent of interruption. The Class I interruptible rate includes a demand charge to reflect the marginal costs of the generation, transmission, and distribution capacity required to maintain service at a target level of reliability. Class II interruptible service, which has no minimum reliability specification, is provided only when utility capacity is available and thus has no demand charge included in its rate.

Various forms of back-up power service are defined and their marginal costs of service discussed. The lack of information on the load demands of back-up customers will, much of the time, make the creation of a separate cost-based rate class for these customers difficult. Where the number of customers is small and their load demands uncertain, including back-up customers in regular rate classes or adopting an experimental rate with interruptible (or off-peak) provisions may be a commission's most prudent short-run course of action until more is known about the characteristics of potential back-up subscribers.

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CHAPTER 1
INTRODUCTION

In this report, methods are developed for calculating marginal cost based rates in three special electric tariff situations: the purchase of electricity from cogenerators and the sale of interruptible and back-up power. These methods are intended to assist state public utility commissions in evaluating the applicability of marginal cost pricing principles to the solution of these special ratemaking problems. As such, this report should be viewed as an attempt to fill a current void in the informational and analytical resources available to state commissions.

Power supplied to utilities by cogenerators can be delivered on a firm basis or on an as-available basis. Costing and pricing methods are presented for both types of deliveries. The methods presented apply equally to ratesetting for utility purchases from cogeneration and small power production facilities qualifying for the special ratemaking provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA), Section 210. For the sake of brevity and convenience, the word cogeneration (and its variations) will be used generally to refer to ratemaking for both types of qualifying facilities. Interruptible service is that supplied to a customer with a provision that allows the utility to interrupt the customer's power supply for short periods, usually during times of extreme peak demand or other system emergency conditions. Back-up service can take any of three forms: supplementary power, maintenance power, and stand-by power. Supplementary power is that sold to a customer to make up the difference between his needs and what he can regularly generate himself. Maintenance power is that provided to a customer during scheduled outages of his facility. Stand-by service is defined as that provided to customers during unscheduled outages of their primary systems.

Background

The decade of the 1970s brought dramatic changes in the political economies of energy production and consumption in the United States. The ten-fold increase in the price of imported oil and the growing uncertainty about its continued availability (at any price) have led the list of reasons for national re-examination of energy policies. One area that has received a large share of policymaking attention in this re-examination process is the regulation of electric utilities.

Rapidly rising fuel costs, together with escalation in the cost of capital equipment and labor, have resulted in substantial increases in the cost of electric energy for most consumers. The upward surge has been particularly noticeable since, for many years, the economies associated with realization of large-scale production allowed electricity's price per kilowatt-hour to fall at the same time that the prices of most other goods were rising. Developments of the 1970s reversed this downward trend and caused public utility commissions to become increasingly interested in mechanisms for combatting the steady rise in electricity prices.

As the cost of electricity has risen, so have concerns about the equitable recovery of this cost from utilities' ratepayers. Possible subsidies of one class or category of users by another received less attention when electric costs were declining. However, as the size of customers' electric bills has risen, so have the pressures for more equitable ratemaking.

Higher costs also have called attention to two other aspects of utility operations: efficiency and energy conservation. Efficiency in the electric utility industry has two distinct but related elements: its engineering and economic aspects. In the engineering sense, efficiency generally refers to the process of achieving high productivity, so that a maximum amount of electricity is generated from a given amount of fuel and a fixed amount of investment in plants and equipment. This often means minimizing the amount of time a base load plant is idle or not fully productive. Economic efficiency, on the other hand, requires the allocation of scarce, energy-producing resources in such a way that results in output being produced only for those purposes justified by the cost, and not for economically wasteful purposes. Conservation depends on the elimination of inefficiency and waste in both production and consumption of electric energy.

Many of the problems relating to customer cross-subsidization, improving utility efficiency, and conserving scarce resources have been caused by the faster growth of utility peak demand (when both costs and scarce fuel consumption are greatest) relative to off-peak demand (when both are lowest). Many regulatory reforms, therefore, have been aimed at altering this trend in growth of peak demand, or at least softening the negative impacts of that part of it which cannot be altered.

In this regard, PURPA Section 101 supplements otherwise applicable state laws to establish conservation, efficiency, and equity as purposes of utility regulation. Its provisions require state utility commissions to adopt or consider adopting measures oriented toward achievement of these purposes. Section 111 of PURPA is also notable in that it establishes six ratemaking standards for state commissions to consider as tools for achieving these regulatory goals. The six standards are:

1) basing all rates on cost-of-service for the utility;
2) eliminating declining block-rate structures in electric ratemaking;
3) establishing time-of-day rates in electric ratemaking;
4) establishing seasonal rates for electric consumption;
5) requiring utilities to offer interruptible rates; and
6) requiring utilities to offer appropriate load management techniques to their customers.

Furthermore and especially relevant to the purpose of this report, Section 131 of PURPA authorizes the Secretary of the U.S. Department of Energy (DOE) to prescribe voluntary guidelines for state commissions to use in their consideration of these PURPA ratemaking standards. In its proposed Voluntary Guideline Number 4, the DOE has recommended that marginal cost principles be used in implementing the cost-of-service standard.[1]

Current Controversies in Electric Utility Pricing

One of the most familiar current debates in public utility regulation is over the proper method for analyzing costs for the purpose of pricing a utility's output.[2] Nowhere is this controversy more focused than in electricity pricing. The debate centers primarily upon what should be considered the "true cost" of providing electric service, especially for purposes of constructing equitable rates and providing correct price signals to consumers. Antagonists align themselves either with the more traditional and often more familiar average cost approach (also commonly referred to as embedded cost, historic cost, accounting cost, or fully distributed cost method) or the non-traditional and often less well understood marginal cost approach. Since the general issues, implications, and problematic concerns associated with each approach are widely discussed in the literature,[3] no attempt will be made to recapitulate or advance the discussion here. Nor does this report or its authors advocate or seek the

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[1]Federal Register, Vol. 45, No. 173, September 4, 1980, pp. 58767-68.

[2]For an erudite and comprehensive but plainly worded introduction to the economics of public utility pricing, see Edward E. Zajac, Fairness or Efficiency: An Introduction to Public Utility Pricing (Cambridge, Mass.: Ballinger Publishing Company, 1978.)

[3]For those not already familiar with traditional electric costing and pricing methodologies, see for example, James C. Bonbright, Principles of Public Utility Rates (New York: Columbia University Press, 1961); and John J. Doran, et al., Electric Utility Cost Allocation Manual (Washington, D.C.: National Association of Regulatory Utility Commissioners, 1973). For

adoption of one or another of the approaches by ratemaking authorities. Rather, it seeks to help fill what appears to be an information void in the regulatory community: methods for applying marginal cost pricing principles in special electric tariff situations. In particular, how does one go about developing and considering a marginal cost based rate for cogeneration purchases, interruptible service, and back-up services?[4]

Basic Principles of Marginal Cost Pricing

For years economists have noted the benefits of marginal cost based prices and have advocated their use. Not until fairly recently, however, has the concept of marginal cost pricing received widespread attention in electric utility ratesetting in the United States. Economic theory states that maximum economic benefits to society can be achieved if prices are set equal to marginal costs. Marginal cost is the cost of producing one additional unit of an industry's output, other things remaining the same. If the price of all units sold is set equal to the marginal cost, the customer will pay an amount that adequately reflects the cost to society of producing the product. In this way, economic efficiency is achieved in that society's scarce resources are used in productive processes where the prices of finished goods and services adequately reflect the actual costs of producing them.

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overviews of marginal cost pricing as it pertains to the electric utility industry, see Alfred E. Kahn, The Economics of Regulation, vol. I (New York: John Wiley & Sons, Inc., 1975); Edward E. Zajac, op. cit.; and Daniel Z. Czamanski, J. Stephen Henderson, Kevin A. Kelly, et al., Electric Pricing Policies for Ohio, 2 vols., NRRI-77-1 (Columbus: The National Regulatory Research Institute, 1977). For a comparative discussion of average vs. marginal cost approaches, see Kevin A. Kelly, et al., "An Outline Discussion of the PURPA Ratemaking Standards," Columbus, Ohio, September 1980.

[4]The need for assistance in these ratemaking areas was initially identified in a roundtable meeting conducted by the NRRI of state utility commissioners and senior staff in attendance at the Annual Meeting of the National Association of Regulatory Utility Commissioners in Atlanta, Georgia on December 5, 1979.

The cost of producing electricity varies by time of day, day of the week, and season of the year. This pattern results primarily from the fact that load demands placed on the utility's generating system vary significantly along these time dimensions. This creates a series of peak and off-peak demand periods, each with its own optimum mix of generating plant types best suited to meet it. Since these optimum configurations have different capital and operating expense requirements associated with them, total and average production expenses vary accordingly. For the same reasons, the marginal cost of meeting an electric load increment (or decrement) also varies.

Economists believe that electric rates based on variable marginal costs send the correct price signals to consumers. Only by setting electric rates as closely as possible to the utility's marginal production costs, economists say, can regulators communicate to consumers the actual cost consequences of expanded consumption and thus enable prices to serve the interests of economic efficiency. Other analysts question the validity of the economists' notion of economic efficiency, particularly as it applies to the regulated sectors of the economy. The primary purpose of rate regulation, as these analysts see it, is to ensure that prices are fair and not necessarily to influence the consumption behavior of ratepayers. Regulators should be concerned that rates are fair to the utility: they should result in revenue adequate to cover the company's operating expenses and to provide a fair return to investors. Rates must also be fair to consumers: they must not be higher than necessary to cover legitimate company costs, and they should sufficiently differentiate among customer classes according to the costs each imposes on the utility system. From these analysts' viewpoint, pricing electricity on the basis of average costs achieves a rate that satisfies these criteria.

The most familiar aspects of marginal cost based electric ratemaking are time-of-day (TOD) and seasonal pricing,[5] but there are other potential

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[5]TOD and seasonal rates also can be calculated on the basis of aver-

areas for its application. While this report will not seek to resolve the theoretical issues separating marginal cost from average cost pricing advocates, it will explore some of the less familiar areas of electric marginal cost pricing applications. Since most electric rates in the United States are based on one or another variation of average cost pricing, its ratemaking implications are fairly well known. Marginal cost pricing applications to electric ratemaking, on the other hand, are relatively new. Despite two years of intense debate, their implications for electric ratemaking still are not fully understood by all regulators or members of the utility industry. The rulings of the U.S. DOE and the Federal Energy Regulatory Commission clearly imply that marginal cost principles should be considered in the PURPA process. Lastly, rates for purchases from cogenerators (Section 210), interruptible rates (Section 111 and 210), and back-up rates (Section 210) are among the less familiar ratemaking areas in which state commissions and electric utilities will have to take some action under PURPA.

Organization of the Report

The remainder of this report contains six chapters and is organized into three parts. Part I deals with marginal cost ratemaking for utility purchases from cogeneration and small power production facilities based on the utility's avoided costs as a result of making these purchases. Part II covers marginal cost ratemaking for interruptible electric service. Part III applies marginal cost principles to setting rates for various types of back-up electric service. Each part contains two chapters. The first contains an introduction to the ratemaking area, including reviews of recent regulatory developments and discussion of some of the more prominent issues involved in ratemaking for each service. The second presents methods for computing relevant utility marginal costs and marginal cost based rates.

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age costs. Many electric utility industry analysts advocate TOD and seasonal rates based on average costs as the best solution to the time-differentiated cost problem.

PART I

MARGINAL COST RATEMAKING FOR POWER PURCHASES FROM COGENERATION AND SMALL POWER PRODUCTION FACILITIES

CHAPTER 2

INTRODUCTION TO COGENERATION RATEMAKING

Cogeneration

Cogeneration is commonly defined as the coproduction of electricity and thermal energy from a single heat source. Because of its dual-energy output, a cogeneration system offers a greater potential for fuel utilization than is possible from a single-output system. For example, conventional electric generating systems have fuel efficiencies ranging from 33% to 42%. That is, only 33% to 42% of the system's fuel input is converted into useful energy (i.e., electricity) and the rest is rejected as waste heat. Similar efficiencies are common to industrial boilers and furnaces that produce steam to be used only for manufacturing processes. Cogeneration systems, which utilize steam for both electric generation and manufacturing processes, may yield a net fuel savings of 10% to 30% over separate systems.[1]

Because more energy from a given amount of fuel is used, cogeneration has captured the attention of policy makers concerned with energy conservation and the optimal use of utility resources and facilities. Electric utilities and industrial firms also are studying the feasibility of cogeneration as a means to reduce fuel costs and increase the reliability of electric service.

Although cogeneration has received increasing attention within the past few years, it is not a newly applied technology. Used by industry since the late nineteenth century, cogeneration reached a peak during the

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[1]Peter G. Bos and James H. Williams, "Cogenerations's Future in the CPI," Chemical Engineering, February 26, 1979, p. 105.

1940s. It began to decline as the cheaper power produced by large, centralized utility generating plants became available. By 1976, cogeneration systems provided less than 10% of the total energy consumed by the U.S. industry.[3]

Even though the level of electric rates generally declined during the third quarter of this century (at least until the 1973 oil embargo), it has been reported that utilities often charged cogenerators discriminatory (high) rates for stand-by and back-up service.[4] These charges eliminated or severely reduced the savings that firms were able to realize through cogeneration, thereby discouraging potential cogenerators from investing in cogeneration systems. A further disincentive existed in that utilities often offered prices for the purchase of a cogenerator's excess output which were about equal to the cost of fuel to produce the power. These prices were usually less than the cogenerator's cost of production.[5]

Cogeneration from the Utility and Industrial Perspectives

Given adequate engineering solutions to the problems associated with interconnected systems, utilities could benefit from the opportunity to improve the reliability of their electric service through the purchase of cogenerated power, particularly during periods of peak demand. Further, if the quantity and reliability of cogeneration within a utility's service area were sufficient to reduce or postpone the need for additional generating capacity, some utilities could improve their financial situations by delaying construction of costly base load plants, reducing their use of fuel-intensive peaking units, and eliminating some expensive purchased power costs. These developments could benefit both the utility and the utility's customers.

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[3]Ibid.

[4]Robert H. Williams, "Industrial Cogeneration," Annual Review of Energy 3 (1978), p. 316.

[5]Ibid.

However, a utility's earnings growth depends largely on its growth in capital investment in plant. Cogeneration can restrict such growth. A further incentive to invest in generating capacity is provided by investment tax credits, which allow utilities a substantial reduction in federal income taxes based on annual expenditures for new plant and equipment. Certain preferential features in the tax code for accelerated depreciation have similar effects. Thus, if the need to build additional utility generating facilities is deferred by the purchase of a sufficient amount of cogenerated power with no compensating financial incentives, the utility could feel that its earnings and financial stability are threatened by cogeneration development.

Utilities also have expressed concerns over the reliability of the cogenerated power entering their grid systems, reminiscent of the "system integrity" arguments used by the Bell system in resisting the attachment of non-Bell terminal equipment to its network. In addition, there is a potential threat to utility system safety standards posed by interconnection with cogenerators.[6] These concerns could be mitigated, however, by utility supervision or operation of the cogeneration system. With utility personnel overseeing the system's operations, safety standards and the quality and reliability of service could be maintained at the levels required by the utility.

Historically, industrial firms also have been reluctant to invest in cogeneration because they feared being classified and regulated as a public utility, particularly if they had surplus power to sell. Under the Federal Power Act, for example, the wholesaling of cogenerated power to a utility having interstate transmission connections would fall under the jurisdiction of the FERC. Thereby classified as a public utility, every aspect of

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[6]Blair A. Ross, "Cogeneration and Small Power Production Effects on the Electric Power System," Paper presented at The National Regulatory Research Institute Conferences on the FERC Cogeneration and Small Power Production Rules and their Impact on State Utility Regulation, 17-27 June 1980.

a cogenerator's financial activities could be examined through the FERC ratemaking process. Further, the value and depreciation schedules for an industry's entire plant could be subjected to FERC review.[7]

Because of this threat of regulation by federal or state authorities, as late as 1979 none of the industrial cogeneration systems in the U.S. were exporting their power.[8] Rather, they produced only enough electricity to meet most or all of their internal needs and purchased supplemental or back-up power from the utilities.

In addition to regulatory pressures, prospective cogenerators face certain technical and financial considerations when evaluating an investment in cogeneration. Among these are the following.

1) Steam volume requirements. Generally, cogeneration is uneconomical for a system requiring less than 400,000 pounds of steam per hour. Systems with this minimum demand represent only 40% of the industrial steam load.[9]

2) Load fluctuations. Cogeneration systems require a fairly constant ratio of thermal energy to electricity. Many manufacturers, however, have fluctuating and disproportionate needs for steam and electric power.[10]

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[7]Peter A. Troop, "Cogeneration in a Changing Regulatory Environment," Chemical Engineering, February 26, 1979, p. 112. This threat is largely removed, however, by the FERC PURPA Section 210 rules. See the next section of this chapter.

[8]Ibid.

[9]U.S. Congress, House Subcommittee on Energy and Power, Committee on Interstate and Foreign Commerce, Report on Centralized vs. Decentralized Energy Systems: Diverging or Parallel Roads?, Congressional Research Service, Library of Congress, 96th Cong., 1st Sess., May 1979 (Washington, D.C.: Government Printing Office, 1979), p. 202.

[10]Richard A. Edelman and Sal Bongiorno, "Cogeneration--A Viable Alternative," Public Utilities Fortnightly, December 6, 1979, p. 37. This problem could become irrelevant under the simultaneous buy-sell provisions of FERC rules pursuant to PURPA, Section 210.

3) Scarce capital. Given the many competing demands for capital investment funds, managers may be unwilling to invest in ancillary equipment that is not directly related to production of primary output, or to hire the trained personnel necessary to operate a cogeneration system.

Additional site-specific factors that may affect a cogeneration investment decision include the cost and availability of fuel, land requirements, local building codes, and environmental regulations.

With so many factors militating against industrial applications, it is hardly surprising that the prevalence of cogeneration has declined since the beginning of this century and that today its potential remains still largely underdeveloped.

Federal Action on Cogeneration

In its deliberations leading up to passage of the National Energy Act of 1978, the U.S. Congress recognized that cogeneration could make a significant contribution to the nation's efforts to conserve energy resources and meet future needs, but that without some utility rate reforms and the lifting of certain federal and state regulations which would apply to cogneration operations, its potential would probably not be realized. Accordingly, a portion of the legislation was designed to remove these obstacles to cogeneration development.

Section 210 of PURPA prescribes the FERC to issue rules for power transactions between cogenerators and utility companies. The FERC issued rules pursuant to Section 210 effective March 20, 1980 and assigned the responsibility for implementing the rules to state regulatory authorities. Essentially, the rules require that utilities do the following:

1) purchase excess power produced by cogenerators at a price equal to the full avoided cost to that utility of generating or purchasing an

equivalent amount of power; and

2) provide supplementary, back-up, maintenance, and interruptible power to cogenerators at non-discriminatory rates.

In addition, the rules exempt cogenerators from classification and regulation as public utilities under most provisions of federal and state laws.

Concerning rates for the purchase of a cogenerator's excess capacity, the rules require state regulatory authorities to review cost data from each utility system under their jurisdiction in order to determine the utility's potentially avoidable costs. These costs are to be considered along with other factors in the determination of the utility's rate schedule for cogeneration purchases. By November 1, 1980, utilities were to submit the following data (or alternate data that the state commission feels is adequate) for determining avoided costs:

1) the estimated avoided cost on the utility's system, solely with respect to the energy component, for various levels of purchases, stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, for the current calendar year and each of the next five years;

2) the utility's plan for addition of capacity by amount and type, purchases of firm energy and capacity, and capacity requirements for each year during the next ten years; and

3) the estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, in cents per kilowatt-hour; costs are to be expressed in terms of individual generating units and individual planned firm purchases.[11]

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[11]U.S. Federal Energy Regulatory Commission, "Final Rule on Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978," Docket No. RM-790-55, Order No. 69, Federal Register 45, no. 38, 25 February 1980, p. 12234.

The other factors that state commissions are to consider in determining a utility's avoided cost are:

1) the availability and reliability of cogenerated capacity or energy during the utility's daily and seasonal peak periods;
2) the relationship of the availability of energy or capacity supplied by the cogenerator to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and
3) the cost or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a cogenerator, if the utility generated its own power or purchased an equivalent amount from another source.[12]

To evaluate these factors fairly, state commissions may need to request additional information from the utilities regarding the number and type of customers in their service areas with the potential for providing cogenerated power to the utility's system. Projections of the amount of power available for the utility's purchase may be itemized on an individual and aggregate basis during periods of peak, off-peak, and system emergencies over the next several years to aid the commission in evaluating potential avoided costs for the utility.

Some Issues in Setting Cogeneration Rates

Full Avoided Costs versus "Split-the-Savings"

While the FERC rules on PURPA Section 210 generally require that rates for utility purchases from cogenerators and small power producers be set equal to the utility's avoided cost, the rules also provide for granting of waiver from this requirement (§292.403). Such waivers will be granted by the FERC when an applicant (state commission or nonregulated utility)

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[12]Ibid., p. 12235-36.

demonstrates that payment of full avoided costs is unnecessary to the encouragement of cogeneration and small power production development. In its hearings preceding the issuance of its final rules, the FERC considered many arguments for and against "split-the-savings" approaches to cogeneration ratemaking.[13] The arguments for paying qualifying facilities a rate for their power which lies somewhere between their own production cost and that of the utility are in some ways indeed persuasive. The primary thrust of these arguments is that, since utilities have little or nothing to gain financially from the full avoided-cost pricing arrangement, they are likely to pursue interconnection with cogenerators less enthusiastically than they might if allowed to share in its financial benefits. "Split-the-savings" is the general pricing norm used for pricing utility purchases from other utilities in pooling arrangements, and its advantages to both buyer and seller have been offered as an explanation for the success of power pooling in many parts of the country.[14] Advocates of this approach to setting cogeneration rates suggest that if all financial incentive is removed for utilities to facilitate cogeneration development, the original purpose of PURPA Section 210 (encouraging the development of cogeneration and small power production) may well be thwarted.

Proponents of full avoided-cost rates, on the other hand, contend that it is impossible to estimate how much cogeneration and small power production development would be made financially infeasible by rates set below utility full avoided costs. The FERC concluded in its final rules that greater jeopardy to the full development of decentralized generation sources would be likely to result from failure to offer full avoided-cost rates than from failing to provide financial incentives to utilities.

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[13]For review of the pros and cons, see Federal Register, op. cit., pp. 12223-4.

[14]Joseph Jenkins, "Use of Florida's Energy Broker to Determine Short-Run Avoided Costs," Paper presented at The National Regulatory Research Institute conferences on FERC Cogeneration and Small Power Production Rules and their Impact on State Utility Regulation, Atlanta, Georgia, 20 June 1980.

Marginal Cost and Average Cost

The FERC rules, §292.304(a)(i), also provide that rates for purchases "be just and reasonable to the electric consumer of the electric utility...."[15] This requirement applies when considering the situation in which an electric utility's rates for sales (which determine its revenues) are based on average production costs, and its rates for purchases from cogenerators and small power producers (which determine some of its expenses) are based on marginal (avoided) costs. One can argue in this case that the marginal (avoided) cost rate for purchases is unjust and unreasonable to the utility's consumers. The difficulty is perhaps best illustrated by the potential consequences of a simultaneous buy-sell arrangement between utilities and their cogeneration and small power production suppliers. With simultaneous buy-sell, a cogenerator sells all his output to the utility and purchases all his requirements. With such an arrangement, a cogenerator could be consuming 125 MW on-peak at the utility's average cost rate and, at the same time, be supplying the utility 125 MW on-peak at a rate equal to the utility's marginal cost. Since prudent purchased power costs are normally treated as necessary operating expenses and become part of the utility's revenue requirement, the other utility customers would eventually have to pay the difference in this transaction.

Supplier Competition for Utility Avoided Costs

Questions may arise over whether equal avoided capacity cost credits should be paid for every kilowatt of capacity supplied by all cogenerators, especially when the utility plans to add only modest amounts of new capacity. For example, a utility may have only 100 megawatts of current and anticipated future unmet demand for capacity. One cogenerator may come on line and agree to supply 80 megawatts of that capacity requirement. A second cogenerator may also want to supply 80 megawatts of firm capacity to the utility. In addition, a group of producers of solar and wind power,

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[15] Federal Register, op. cit., p. 12235.

who have been compensated for their individually random deliveries to the utility at its avoided energy cost, may have collected enough data to determine that the aggregate capacity-value of their supply to the utility is 10 megawatts. The utility's total avoided capacity costs can only be equal to that of 100 megawatts, but to whom and by what formula should these costs be paid?

Some may argue that avoided capacity credits should be paid to suppliers on a first-come basis until they are all gone. The utility's need for long-term firm capacity supply contracts, in fact, may require this approach. Others may suggest that, for reliability purposes, the number of suppliers should be maximized and that this goal suggests sharing of capacity credits among all suppliers with firm capabilities. It may be wise for a commission to establish its position early on this issue since the price to be paid by utilities will affect potential cogenerators' investment decisions.

CHAPTER 3

METHODS FOR COMPUTING MARGINAL COST BASED ESTIMATES OF UTILITY AVOIDED COSTS AND CONVERTING THESE COSTS INTO RATES

To comply with the mandatory FERC rules pursuant to Section 210 of PURPA, a state commission must determine the energy and capacity costs that each utility under its jurisdiction can avoid by taking power from a cogenerating facility, as compared to generating the power itself or buying it from another source. These avoided costs are to be the basis for setting rates for the utility's purchase of cogenerated power.

This chapter presents two methods for calculating marginal cost based estimates of these costs. The first is an idealized method that ignores limitations of data availability, costs of data acquisition, and resources required to make computations. As such, its primary value may be to serve as a conceptual standard for evaluating the shortcomings of more practical approaches. The second is a simplified method and is based on an approach originally developed by Ralph Turvey.[1] It may be judged a more practicable approach to calculating avoided costs. The last section of this chapter offers guidance on converting avoided cost estimates into rates.

Before presenting marginal cost based methods for calculating avoided costs and rates, this chapter begins with discussion of the relationship

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[1]Ralph Turvey, Optimal Pricing and Investment in Electricity Supply (Cambridge: MIT Press, 1968); see also Charles J. Cicchetti, William J. Gillen, and Paul Smolensky, The Marginal Cost Pricing of Electricity: An Applied Approach, A Report to the National Science Foundation on behalf of the Planning and Conservation Foundation, Sacramento, 1976; and Stephen N. Storch, A Users Manual for MARGINALCOST, A Computer Program Developed by Charles J. Cicchetti, (Columbus, Ohio: The National Regulatory Research Institute, 1977).

between the concepts of marginal cost and avoided cost. It also examines the structure of electricity production costs with an eye toward identifying those which can be avoided as a result of making purchases from a cogenerator.

Marginal Costs and Avoided Costs: How Are They Related?

Marginal Costs of Electric Generation

In economics, marginal cost is defined as the additional expense (or savings) associated with producing, delivering, and selling one additional (or one less) unit of a good or service. In the electric utility industry, the relevant measures of marginal output are kilowatts (kW) and kilowatt-hours (kWh). A kilowatt (kW) is a measure of the capacity to supply electricity at any one time; as such, it can be thought of as a measure of electric power. A kilowatt-hour (kWh) is a measure of electric energy. Therefore, if one kW of capacity supplies energy for one hour, the amount of electric energy supplied is one kWh.

In electricity production, increases (or decreases) in demand for capacity and increases (or decreases) in demand for energy are both important in understanding electric marginal costs. Incremental changes in system demand for electric energy (kWh) that are concentrated into a few peak hours require greater increments of available generating capacity (kW) than do the same number of incremental kilowatt-hours of demand spread over an entire day. In addition, the degree of permanence of the increment affects the manner in which a utility expands to meet it. In the short run, a utility will expand utilization of its existing generating capacity or purchase electricity from other utilities (whichever is cheaper) to meet temporary fluctuations in demand.[2] In the long run, when increments in demand can be shown to be relatively permanent in nature, a utility's most

[2]If short-term demand increments are great enough, of course, the utility may do both.

prudent course of action normally is to plan for and build additional generating capacity to meet the increment. The type of capacity added will depend on the magnitude (kW) and duration (number of hours) of the demand increment that must be met.

Therefore, when speaking of the marginal costs of meeting increments in electricity demand, one must distinguish between short-run versus long-run increments and the cost consequences associated with each type of change. In the short run, the relevant marginal costs are the running costs associated with greater utilization of existing generating plants, plus any costs of purchasing additional power beyond that available from full-time operation of the utility's own stations. In the long run, relevant marginal costs include the construction costs of additional plant(s) required to meet expanded demand, plus the operating costs of those plants. The first set of costs are referred to as short-run marginal cost (SRMC); the second long-run marginal cost (LRMC).

Before turning to consideration of avoided cost, one additional aspect of utility marginal cost must be mentioned: the variability of both SRMC and LRMC according to the time of day, day of week, and season of the year. Because of the requirements of daily living and the diurnal routines most people follow to meet them, the load generating requirements of an electric utility are different, for example, at 2 p.m. than they are at 2 a.m. each day, and at 6 p.m. than they are at 11 p.m. Furthermore, because most places of work schedule more activities Monday through Friday than they do on weekends, hourly loads are different during the week than on Saturday and Sunday. Lastly, because of weather, number of daylight hours, and seasonal variation in people's daily activities, a utility's generating requirements are typically different in summer than they are in winter.

Electric companies utilize a variety of generating technologies, with varying costs of operation, to meet these varying levels of demand. They include three basic types:

1) peaker plants - relatively small-capacity generators, often powered by internal combustion engines;

2) cycling plants - intermediate-size generators, typically older and smaller plants formerly used for meeting base load; and

3) base load plants - large-capacity generators powered by steam turbine engines, with steam boilers fired by either coal, nuclear fission, or fuel oil.

Hydroelectric plants may fall into any one of these above three categories, depending on their size.

Each type of generation is most efficient for meeting loads of particular size and duration. Baseload plants produce the least expensive electricity of all (in terms of ¢/kWh), but only when they are run more or less continuously. Peakers usually have the most expensive running costs, but are overall least expensive for meeting smaller loads lasting only for short durations. Cycling plants are intermediate with respect to running cost (¢/kWh) and size and duration of load for which they are optimally efficient.

In general, utilities minimize generating costs by utilizing the optimum mix of technologies available to them to meet varying loads as they occur at different times of the day, week, and year. Because of the variability in time durations of particular load levels and the differences in capacity and operating costs of the combination of generating technologies most efficient to meet them, utility generating costs may vary dramatically by time of day, day of week, and season of the year.

Avoided Costs of Electric Supply

As already discussed, FERC rules on PURPA Section 210 require state utility commissions to set prices for cogenerators' output equal to the cost utilities can avoid as a result of not having to generate the power themselves. The rules require consideration of both capacity (kW) and energy (kWh) costs.

The preceding discussion of electric utility marginal production (generating) costs suggests that the short-run and long-run value (in terms of additional production costs avoided) of cogenerators' power supply will depend on its timing, kW-level, duration, reliability, and permanency. The first three of these supply characteristics, when compared to the utility's current load curve and available generating plant, affect the short-run avoided (or decremental) costs realizable by the utility as a result of purchasing the cogenerators' output. The last two, when combined with the first three and compared to the utility's anticipated future demand and the expansion plan designed to meet it, influence the utility's long-run avoided (or decremental) costs.

The Structure of Utility Costs: What Costs Can Be Avoided as a Result of Purchases from Cogenerators?

Electric utilities' operating costs consist of those that are largely avoidable as a result of power purchases (generation costs) and those that either are unavoidable or about which generalizations are difficult (transmission and distribution and other costs).

Generation Costs

With respect to the capacity (kW) component of cogenerator power deliveries, the costs of additional generating capacity can be totally avoided by a utility when two basic conditions are met:

1) the utility has (current or anticipated) unmet demand for capacity (kWs) in its service area; and

2) the cogenerator's power deliveries are firm or have firm characteristics, i.e., the kW-level, timing, and duration, as well as number of years over which deliveries will be made are predictable; and they coincide with the utility's current and anticipated unmet load demands.

With respect to the energy component, utility energy (or variable operating) cost can be avoided _en toto_ as a result of purchases from a cogenerator, providing certain provisions for deliveries are followed:

1) adequate notice of the timing of power deliveries (or nondeliveries must be given in order to permit adequate adjustments in the utility (or power pool) generating dispatch system;

2) adequate delivery durations must be assured in order to avoid inefficient stopping and starting of certain generating units; and

3) adequate MW-levels of deliveries must be assured so as to efficiently displace the operation of a generating unit.

Transmission and Distribution Costs

A utility's demand-related transmission costs may be higher or lower for power purchased from a cogenerator, depending on the relationship between the geographic location of the cogeneration facility and the location of the utility's high-demand market areas. Usually expressed in terms of line losses reflecting the additional energy needed to transmit power over substantial distances, energy-related transmission costs also could be more or less for cogenerated power than for power generated by the utility or purchased elsewhere. These costs depend on the voltage level of the cogenerated output and the location of the cogeneration facility with respect to the utility's primary market areas. Customer-related transmission costs for cogenerated power again depend on the cogenerator's location in relation to the utility's customers, and they may be greater or less than for other sources of utility power.

Making purchases of power (from any source) instead of self generating would seem to be totally unrelated to a utility's incurrence of distribution costs.

Marginal Cost Based Methods for Computing Utility Avoided Costs

There are a number of possible methods, from simple to more complex, for estimating utility avoided costs from a marginal cost perspective. Each has its own trade-offs in expected accuracy compared to the time and resources required to execute the method. Complex estimation procedures involving forecasting, use of large data banks, and extensive computer simulation are expensive. Simpler, shorthand approaches, such as those discussed later in the report, often yield adequate results at a fraction of the cost, but they also usually contain simplifying assumptions that may cast doubt on the validity of the estimates they produce. A commission's ultimate choice of method will depend in large measure on its judgments about these trade-offs, the expected importance of power from decentralized generating sources in the utility's future supply picture, as well as the resources available to the commission for making the estimates.

As discussed earlier, incremental and decremental demands for electricity have both short-run and long-run cost consequences for a utility. Practically speaking, estimating the short-run marginal costs of load increments and decrements is easier than estimating the long-run marginal costs. This is because utilities reoptimize their system expansion plans in the long run in response to changes in expectations about long-run load patterns. It is the forecasting of long-run load changes and the estimation of the costs of utility responses to these load changes that can make the long-run electric marginal-cost estimation process difficult, complex, and expensive. Estimating utilities' avoided costs of capacity as a result of making cogeneration purchases is a long-run marginal-cost estimation problem.

In this section, we present two approaches to the long-run avoided cost estimation problem. The first is an idealized method that largely ignores inherent problems of data acquisition and computation costs, as well as the time required to make the calculation. While not practicable for application in all cases, the idealized method is intended to be at least instructive for the analyst in understanding the scope of the cost estimation problem. As such, it can serve the important purposes of identifying weaknesses in more abbreviated shorthand methods, the points at which errors are likely to creep into shorthand estimates, and an indication of how serious these errors are likely to be.

In avoided cost estimation for purchases of energy from cogenerators, the utility's avoided cost is equivalent to its short-run marginal cost, in this case its short-run decreased cost of system operation. The methods for obtaining an estimate of this cost are simpler than those for long-run avoided cost estimation, so we deal with them first.

Purchases of Energy

Power deliveries that either are not guaranteed by contract or have no firm capacity value in their aggregate are useful to the utility only in terms of its being able to avoid system operating costs. They cannot be depended upon when the utility is planning for its current and future generating capacity needs, and thus do not enable the cancellation or postponement of any planned capacity expansions. With adequate notice,[3] however, such deliveries can enable the utility to avoid marginal system operating costs by virtue of enabling it to shut down operation of one or more of its most recently dispatched generating units. Since the utility's marginal operating costs, and thus its avoided energy costs for cogenera-

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[3]It is expected that notice provisions for deliveries will be contained in individual supplier contracts or the standard tariff schedule for cogeneration purchases. Given the dispatching requirements of both the utility and the cogenerator, it is also expected that notice requirements will be incumbent on both the utility and the cogenerator. In the case of the former, FERC rules require state commissions to establish notification procedures whereby a utility may release itself from the obligation to buy power due to such conditions as light load or a system emergency; see Federal Register, op. cit., p. 12236, §292.304, paragraph f. 1. It is also reasonable to require the cogenerator to give notice, especially for randomly patterned deliveries, so that the utility can efficiently adjust the dispatching of its own generating units.

tion purchases, may vary according to time of the delivery, the commission may wish to calculate avoided energy costs by time of day and by season of the year.

Marginal operating costs in cents per kilowatt-hour (¢/kWh) for each generating unit, the system lambdas, are routinely calculated by a generating utility for the purpose of economic dispatch of its units. The lambda for the utility's last unit on line in an hour can be taken as a measure of the marginal operating costs for the system during that hour. For utilities belonging to a power pool, the pool's hourly charges to the utility can be taken as the relevant measures of the utility's marginal operating costs when it is buying from the pool, assuming this is the utility's least cost alternative.

An acceptable marginal cost-based measure of the utility's avoided energy costs, therefore, can be computed for any time period by taking the average of the system lambdas for the period, as given by the following general formula:

$$AEC = \frac{1}{N} \sum \lambda_i \tag{3.1}$$

where

AEC = the utility's avoided energy costs in cents per kilowatt-hour for the period;

N = the number of hours in the period;

λ_i = the system lambda for the i-th hour.

This formula requires taking the mean of hourly system lambdas for all the hours in the period for which the avoided energy cost is to be calculated. If avoided energy costs are to be computed on a time differentiated basis, then separate computations are made for each of the peak and off-peak periods. In the calculations for each period, N becomes the number of hours in the period and the λ_i's are the lambdas for each one of the hours. The formula can also be used for computing a utility's avoided energy cost for a one-year period, without any time differentiation for peak and off-peak. In this calculation, N equals 8,760 (the number of hours in a year) and the λ_i's are the utility's system lambdas for each of those hours. The resulting avoided energy cost is an average measure applying to all hours of the year.

In some circumstances, the commission may want to have the utility pay an avoided energy cost credit that recognizes the varying quantities of energy to be delivered by a supplier over the various hours of the period.[4] Such an avoided energy cost estimate can be computed by weighting the hourly lambdas according to these varying quantities, as shown by the following equation:

$$AEC = \sum_i w_i \lambda_i \tag{3.2}$$

where

w_i = the fraction of total energy in the period that is expected in the i-th hour.

As the total amount of energy being supplied to the utility increases, these equations 3.1 and 3.2 will tend to overestimate its avoided energy costs unless system lambdas are adjusted. As the most costly utility generating plants are displaced by cogeneration purchases, the system's marginal running costs (lambdas) for self-generated power decline.

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[4]This may be the case, for example, when cogeneration purchases are available only during certain hours of the day.

Purchases of Energy and Capacity: An Idealized Method

Firm power deliveries and those which may be individually stochastic in nature but have firm characteristics in their aggregate (e.g., the collective output of solar and wind powered generators) can result in a utility's avoiding both the capacity and energy costs of electric generation. The nine step process presented below comprises what may be thought of as an idealized method for calculating these costs. The bulk of the method deals with estimating avoided capacity costs. Perhaps the most critical step in calculating a utility's avoided cost per kilowatt of capacity purchased from cogenerators is specifying the total amount of utility capacity displacement that will result from such purchases. The nature and magnitude of cogeneration supply determines the number and type of planned plant additions that the utility may be able to delay or cancel. The number and type of plants delayed or cancelled, in turn, determines the utility's total and unit (dollars per kilowatt) avoided capacity costs.

Step 1. Forecast customer demand for electricity over the duration of the utility's capacity expansion planning period.[5] Call this the utility's base case forecast.

Step 2. Run a system capacity expansion planning model using as input this forecast of demand to determine the least cost means for the utility to meet this base case forecast.

The output of this run should include a schedule of plant additions and the present value of the capital and operating costs of generation required to meet the base case forecast.[6]

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[5]The length of capacity expansion planning horizons may vary among utilities. For this idealized method, the horizon should be set at that point in the future beyond which costs incurred (or avoided) by the utility are insignificant when discounted back to the present to account for the time value of money, ignoring the effects of inflation.

[6]We assume the model calculates these present values. For discussion of how to calculate the present value of a future expenditure, consult a standard engineering economics text, e.g., H. G. Theuesan, W. J.

Step 3. Determine whether the utility has planned capacity additions and/or firm power purchases that could be postponed or cancelled as a result of making cogeneration purchases.

If the result of Step 2 shows that the utility should plan neither to construct nor purchase additional generating capacity over its capacity planning period, or that it has as planned additions only that construction in progress that cannot be prudently delayed, then no capacity costs can be avoided by the utility as a result of cogeneration purchases, and it would be inappropriate to permit avoided capacity credits in the cogeneration rate.[7] The utility can avoid only system operating costs in these situations; to calculate its avoided cost, refer to the subsection, "Purchases of Energy," above.

If the utility has planned capacity additions and/or firm power purchases that could be delayed or cancelled, proceed to Step 4.

Step 4. Forecast the probable amount of firm cogeneration supply that will develop in the utility's service area during the period for which rates will be in effect.

Fabrycky, and G. J. Theusan, Engineering Economy, 4th edition (Englewood Cliffs, N. J.: Prentice-Hall, Inc., 1971), pp. 105-8.

[7]However, in line with the provisions of §292.303 of the PURPA, Section 210 rules, a cogenerator may request the utility to transmit its power to another utility with which the utility is interconnected. The first utility may agree to wheel the power to a second utility or it may decline to do so. If it agrees, then the second utility must purchase the cogenerator's electricity at its (the second utility's) own avoided cost, less an appropriate amount for line losses. The first utility need not agree to wheel the cogenerated power, but if it does not agree, it retains the obligation to buy at its own avoided cost. Cogenerators may wish to pursue this wheeling option for selling their output when the utility in whose service area they are located has excess capacity, is a non-generating utility, or is a small utility with avoided costs lower than the cogenerator might obtain if located elsewhere.

A reasonable forecast of the anticipated capacity value of this cogeneration supply is needed to determine how the utility's capacity expansion plan will be affected by this new source of capacity supply. A part of this forecast is a determination of the number of years duration of this firm power; i.e., will it be available for one year, five years, or permanently? The length of time over which firm power is supplied affects how long a plant addition may be delayed and, within the context of the utility's capacity expansion planning horizon, whether it may be cancelled altogether. The duration of firm supply, therefore, is one factor that determines the total long-run cost of capacity that the utility avoids. To simplify the presentation, we assume here that the forecast of cogenerators' supply of firm power extends through the utility's planning horizon. This supply can be considered permanent for utility capacity planning purposes. When this is not the case, the ratemaker will find it necessary to make separate avoided capacity cost calculations and set separate capacity credits for sources of firm power with different supply durations.

It should also be noted that this forecast of cogeneration supply is limited to the firm power supply that becomes available during the period for which the rate for purchase is to be paid. Firm power that first becomes available after this period is not included in the forecast.

Step 5. Modify the utility's base case load forecast (obtained in Step 1) by the amount of forecasted firm capacity and energy supply from cogenerators (obtained in Step 4). Call this the utility's modified forecast.

The result of Step 5 is a modified utility load forecast (more correctly, modified forecast of its generating requirements) that takes into account the forecasted supply to be purchased from cogenerators.

Step 6. Run a system expansion planning model to obtain a new optimum system expansion plan for the modified forecast (obtained in Step 5).

The output of this run will be a new optimum schedule of utility capacity additions (other than the capacity purchased from cogenerators) needed to meet its modified forecast. Also included in the output should be the present value of the total capital and operating costs of generation required to meet the modified forecast.

Step 7. To find the present value of the utility's long-run avoided cost due to the firm supply of cogenerators, subtract the sum of capital and operating costs obtained in Step 6 from the sum obtained in Step 2.

The result of Step 7 is the difference in present values of the utility's total generation costs (capacity and energy) associated with meeting the base case and modified case forecasts, the latter of which takes into account the firm power supply of cogenerators.

Step 8. Annualize the Step 7 result.

Assuming that the present value of the utility's long-run avoided cost is not to be paid to the cogeneration suppliers in a one-time, lump sum payment, this step is needed to find an annual installment on this cost appropriate for ratemaking. Annualized costs can be obtained according to the following general formula.

$$\text{PVAC} = \text{PVTC}\left(\frac{\text{IR}}{1-(1+\text{IR})^{-N}}\right)$$

where:

PVAC = present-value annualized cost;

PVTC = present-value total costs;

and the expression in parentheses is an annuity factor in which:

IR = interest rate;

N = number of years over which the cost is annualized.

With firm power supply that is permanent, one can take N to equal infinity (∞).[8] In doing so the general formula reduces to the expression:

$$PVAC = PVTC(IR)$$

Step 9. To obtain a unitized measure of the utility's long-run avoided cost, divide the Step 8 result by the annual amount of electricity in kilowatt-hours supplied by cogenerators.

However, the way in which unit avoided costs are calculated ultimately depends on the way in which these costs are to be paid to cogenerators. For example, a commission may want to allow either dollar-per-kilowatt or cents-per-kilowatt-hour payments of avoided capacity costs, depending on facility size, metering considerations, and whether the credit is for a class aggregate capacity value or whether it applies to the output of one facility. The commission may also want to adopt rates for purchases that vary by time of delivery. For discussion of these types of ratemaking considerations, see the following section, "Rates Based on Avoided Costs."

If this method of computing avoided costs is used and separate measures are desired for the utility's dollar-per-kilowatt avoided cost of

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[8]If the firm supply is not permanent, then a finite value for N may be appropriate. The commission will probably choose to set N equal to the number of years for which the cogeneration capacity is considered firm. This increases the value of the annuity factor, but shorter-term capacity supplies also create less difference in the utility's optimum expansion plan so that PVTC is lower and, on balance, the PVAC will also be lower, ceteris paribus.

In practice, any firm supply that extends through the utility's planning horizon can be considered permanent. Without specific information that a source of firm supply is temporary, it should be treated in the same way for avoided cost analysis as increments in demand are treated in ordinary marginal cost analysis. That is, whatever annuity factor is used for calculating utility customer annuity payments should also be used for the utility's payment of avoided cost to its cogeneration suppliers.

generating capacity and its cents-per-kilowatt avoided cost of energy, then the capital and operating cost portions of the output from Steps 6 and 2 should not be combined before performing the subtraction called for in Step 7. The annualized differences in capital and operating costs of the two expansion plans then are divided in Step 9 by the annual kilowatts and kilowatt-hours, respectively, of firm capacity and energy supplied by the cogenerators.

This method of calculating avoided cost has been presented as an idealized one in the sense that it assumes the availability of perfect information and computational aids (computer models). A discussion of its practical limitations is in order. First of all, some of the long-term forecasts that it calls for are in practice impossible to do with any reasonable degree of certainty. They depend heavily on knowledge of future economic events that cannot be well predicted given the current state of the art and science of economic forecasting. Fuel prices are a prime example. As a result, one may prefer not to calculate a utility's avoided energy costs for firm power supply by an expansion modeling process such as the one described above, especially when more direct measures of system marginal operating costs are available. One may choose instead to calculate avoided energy costs using equation 3.2 with up-to-date hourly system lambdas (see the preceding section, "Purchases of Energy"). Secondly, it is true that forecasting cogeneration supply and reoptimizing the utility's expansion plan properly takes into account the size, timing, and duration of cogenerators' firm supply when calculating the utility's avoided cost of generation capacity. However, such a process also yields a measure of avoided capacity cost that is unadjusted for the higher unit energy costs that the utility may incur as a result of delaying or cancelling new plants. Given the mechanics of the method, there is no simple way to estimate these costs and to adjust for them. Simpler methods for estimating a utility's marginal cost of generating capacity, on the other hand, typically share one common feature: they dispense with forecasting and reoptimization of system expansion plans. This can be both a weakness and a strength. When demand increments and decrements are large, the distortions introduced by not reoptimizing the system expansion process may be substantial. One of the strengths of these simpler procedures, however, is that adjusting for changes in system fuel efficiency as a result of adding or not adding a particular type of plant at a particular time can be estimated and accounted for in a straightforward manner. We examine the application of one of these methods in the following subsection of this report.

Purchases of Energy and Capacity: A Simplified Method

The idealized method presented above for calculating a marginal cost based estimate of utility avoided energy and capacity costs may be impracticable as a solution to the avoided cost estimation problem in many situations. Here we present a simpler marginal cost approach for calculating a utility's avoided capacity cost. It is based on the work of Turvey (see footnote 1); has been applied by Cicchetti, Gillen, and Smolensky, op. cit., in developing a computer program called MARGINALCOST; and is illustrated in Storch, op. cit. We will refer to the method as the MARGINALCOST method. The MARGINALCOST approach to long-run avoided cost estimation simplifies the nine-step idealized method in that it bypasses the prescribed forecasting (Steps 1 and 4) and capacity expansion modeling procedures (Steps 2 and 6). To the extent that such a simplified method can be used in estimating the marginal costs to a utility of expanding its electricity supply, it can also be used (with some modification) in estimating the utility's avoided costs associated with reductions in future generation resulting from the purchase of cogenerators' capacity and energy.

In order to make the task of estimating marginal costs more manageable, the MARGINALCOST approach to capacity cost estimation has two significant simplifying steps: it dispenses with forecasting load increments and with reoptimizing the utility capacity expansion plan for meeting the incremental load.[9] Instead, it assumes that the utility

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[9]This discussion draws heavily upon Storch, op. cit., pp. 10 ff.

response to a load increment is to advance its current expansion plan by one year. The utility's marginal cost of generating capacity is then calculated by taking one year of the annnualized capital costs of each plant whose on-line schedule is advanced, adding the fixed operation and maintenance expenses for each plant, and subtracting the total fuel savings to be realized by having brought a newer, more efficient plant on line one year earlier. These costs are converted to current dollars, summed, increased by factors that account for required reserve margin and line losses, and then divided by the sum of the rated capacities of the affected plants. The result, expressed in $/kW, is taken as an estimate of the utility's long-run marginal cost of expanding generating capacity.

In the avoided cost calculation problem, one is required to estimate long-run decremental costs. Where utilities are planning future capacity additions and the MARGINALCOST method can be applied to estimating incremental capacity costs, it can also be applied (in the reverse) for estimating capacity savings. Instead of moving the utility's expansion plan forward, one moves it backward. The cost calculation and variables entered into it are then the same for decremental (avoided) costs as for incremental costs, with two exceptions:

1) instead of fuel savings being realized, additional fuel expenditures are incurred as a result of having less efficient plants on line one year longer; these additional fuel costs are subtracted from the year of annualized capital and fixed O&M expenses avoided for each plant as a result of moving the expansion plan back; and

2) no adjustment for reserve margin requirements or line losses needs to be made because the utility generally does not avoid these costs as a result of making power purchases.

Taking these differences into account, a marginal cost based estimate of a utility's avoided capacity costs can be calculated by a procedure similar to that presented in Table 3-1.

The utility expansion plan and cost data in Table 3-1 are hypothetical, constructed to approximate current costs. The hypothetical planned additions are two 800 MW (800,000 kW) base load units, one coal and one nuclear, scheduled to come on line in 1982 and 1985, respectively. All costs are expressed in 1981 dollars, the year in which the avoided-cost cogeneration rate will be paid. Line (1) contains the total capital cost of each facility, and line (3) presents one year of these costs annualized at a 10% interest rate over a 30-year life for each plant. Line (4) is the annual fixed O&M expenses for each unit. Instead of fuel savings from advancing new plants, line (5) in the avoided-cost calculation table becomes the additional fuel and variable O&M expenses from having older,

TABLE 3-1

HYPOTHETICAL UTILITY AVOIDED COSTS OF GENERATION CAPACITY (IN KW) USING THE MARGINALCOST APPROACH (1981 DOLLARS)

Item	Coal Plant (On Line in 1982)	Nuclear Plant (On Line in 1985)
(1) Capital Cost	$ 480,000,000	$ 800,000,000
(2) Capacity (kW)	800,000	800,000
(3) Annual Capital Cost[a]	$ 50,928,000	$ 84,880,000
(4) Annual Fixed Operation and Maintenance Cost	1,320,000	1,200,000
(5) Additional Fuel Costs	12,000,000	24,000,000
(6) Total Avoided Costs of Generation Capacity = (3) + (4) - (5)	40,248,000	62,080,000

[a]Based on a 30-year life and a 10% interest rate.

Source: Hypothetical data and calculations.

less efficient plants on line one year longer.[10] Line (6) presents an estimate of the present value of the utility's net avoided generating

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[10]Since both of the plants in this example are 800 MW base load

capacity cost for each plant as a result of delaying their introductions by one year. This quantity is calculated by adding the annualized capital cost of the plant to its annual fixed O&M expenses and subtracting the additional fuel expense associated with the operation of older plant(s) one year longer.

The utility's avoided capacity cost per kilowatt is then calculated by summing the net avoided capacity costs for each unit and dividing by the summed kilowatt capacities of the units. For this example:

$$\frac{\$40{,}248{,}000 + \$62{,}080{,}000}{800{,}000 \text{ kW} + 800{,}000 \text{ kW}} = \$63.96/\text{kW}$$ [11]

To convert this estimate to cents per kilowatt-hour, one divides by 8,760, the number of hours in a year.

The MARGINALCOST computer program does not calculate incremental or decremental energy costs; it requires them as an input.[12] One approach to calculating these costs has already been described, the averaging of hourly system lambdas. For instructions, see preceding section, "Purchases of Energy."

For those without computer capabilities or who would otherwise choose to calculate avoided costs by hand, the MARGINALCOST calculations are relatively simple and, given the necessary input data, can be performed with the aid of a calculator in a few hours.[13]

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plants, growth in the utility's generating load is ignored in calculating additional fuel expense. It is assumed that these plants will be in constant operation no matter what year they are introduced.

[11] In the MARGINALCOST procedure this number is multiplied further to account for required reserve margin and line losses for transmission (by voltage level). Since these costs are not avoided by the utility as a result of cogeneration purchases, these multipliers are inapplicable to avoided cost calculation.

[12] Storch, op. cit.

[13] See Cicchetti, Gillen, and Smolensky, op. cit.

Rates Based on Avoided Costs

How Avoided Costs Are to Be Paid

Once a utility's avoided costs have been calculated, the commission must decide how these costs will be paid to cogenerators. If time-of-day metering is already installed on the premises or if its installation is judged to be cost-effective based on the anticipated volume of cogenerator sales to the utility, the commission may want to adopt rates for purchases that vary by time of day. If this option is chosen and the commission has not already done so, utility rating periods for pricing these transactions will have to be defined.[14] To do so, the commission must decide what method it will use for determining the relative amount of avoided capacity costs that will be paid for deliveries during peak and off-peak periods.[15] Avoided energy costs must also be calculated for peak and off-peak periods (see "Purchases of Energy," equation 3.2).

In setting rates for cogeneration purchases, the commission must also determine whether and under what conditions avoided capacity credits will be paid on a dollar-per-kilowatt or a cents-per-kilowatt-hour basis. If capacity credits are to be awarded for only firm deliveries under contract, then avoided capacity costs can be paid on a dollar-per-kilowatt basis for the minimum deliverable capacity in the contract, much in the same way that large consumers of electricity are billed a dollar-per-kilowatt charge for the maximum demand they are permitted to place on the system. Aggregate-

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[14]For an example illustrating how to go about selecting peak and off-peak periods, see Electric Power Research Institute, Electric Utility Rate Design Study, "How to Quantify Marginal Costs: Topic 4," Chapter IV, pp. 25-33.

[15]There are at least three methods for distributing capacity costs to utility rating periods. For a treatment of the MARGINALCOST method, see Storch, op. cit.; for the NERA method, see Electric Power Research Institute, op. cit., Chapter V; and for the EBASCO method, see Electric Power Research Institute, Electric Utility Rate Design Study, "Costing for Peak Load Pricing: Topic 4," pp. 83-88.

value avoided capacity cost credits (paid to a class of producers whose deliveries are individually random in nature) will generally have to be determined on a cents-per-kilowatt-hour basis.

Interconnection Costs

The FERC rules, §292.306, require each qualifying cogeneration and small power production facility to pay the necessary costs of interconnection with the electric utility power grid. State commissions are left to determine the proper amount of these costs, as well as the manner and term for their reimbursement to the utility. The assessment of these costs must not discriminate against the qualifying facility in comparison with the utility's practices toward other members of the same customer class who do not generate electricity; i.e., cogenerator and small power producer interconnection charges are limited to the amount of additional interconnection expense that the utility incurs in order to permit purchases to be made. The FERC rules also permit these charges to be included in calculation of standard rates for purchases.

A recent survey sponsored by the U.S. DOE[16] has uncovered wide variation in utility interconnection practices and attendant costs. It also has found that the criteria for evaluating such practices is far from standardized. This lack of uniformity reflects in part individual utilities' varying philosophies regarding acceptable risk and reliability performance, as well as the fact that protective relaying has long been regarded as an engineering art, affected by designers' judgments about the trade-offs between reliability and cost. Actual interconnection costs were found to range from $60,000 to $691,000 for customers whose capacities ranged from 20 kW to 20 MW. Interconnection requirements appear to be heavily situation-dependent and not necessarily related to the size of the facility. The report recommends that interconnection costs be determined

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[16]James B. Patton, Survey of Utility-Cogenerator Interconnection Practices and Costs, Final Report to the U.S. Department of Energy, Office of Electric Energy Systems (Palo Alto, California: Systems Control, Inc., June 20, 1980.)

on a case-by-case, component-by-component basis, and cautions against making generalizations from "typical" cases described in its survey. A review of the engineering aspects of interconnection, especially as they relate to concerns about system safety and reliability, is contained in a recent paper by Blair Ross, American Electric Power Service Corporation.[17]

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[17]Blair A. Ross, "Cogeneration and Small Power Production Facility Effects on the Electric Power System," Paper presented at The National Regulatory Research Institute Conferences on FERC Cogeneration and Small Power Production Rules and their Impact on State Utility Regulation, June 17-27, 1980.

PART II

MARGINAL COST RATEMAKING FOR INTERRUPTIBLE SERVICE

CHAPTER 4

INTRODUCTION TO INTERRUPTIBLE SERVICE RATEMAKING

Although much of the recent increase in electricity prices has been due to factors beyond utilities' direct control (e.g., fuel expenses, construction costs, and costs of implementing environmental regulations), reduction in the growth of expensive peak demand is one area that still has significant cost control potential for many utilities. If system load can be reduced during extreme peak periods, considerable savings in present and future fuel and equipment expenditures often can be realized.

The term "load management" refers to a variety of methods that a utility may employ to alter the pattern of demand reflected in its load curve. Load management techniques may be either direct or indirect in nature. Indirect techniques rely on incentives to induce consumers to regulate voluntarily the demands they place on the system. Time-of-use rates can be thought of as an indirect load management technique. Direct load management techniques allow the utility to control by electro-mechanical means some portion of the system load. Interruptible rates are an example of a direct load management technique. Customers who choose interruptible service agree to allow the utility to cut off their consumption of electricity when the utility is unable to meet total system demand due to insufficient capacity.

While interruptible tariffs are common to many utilities, the practice of interrupting interruptible customers may vary widely from one company to another. It appears that some utilities may have created interruptible rates (for certain industrial customers, for example) but proceeded to plan and construct capacity as though the subscribers were regular, assured service customers.[1] This practice, where it has existed, violates one of the cost-based rationales for creating an interruptible class in the first place: to conserve capacity and energy costs on peak.

Nonetheless, interruptible service is still one tool available to utilities with the potential for improving system load factor and, hence, reducing required peak generating capacity and peak fuel consumption. In addition, it can be seen as a vehicle for providing greater choice by consumers in selecting the kind of electricity they buy.

Electricity and Product Differentiation

The term "product differentiation" refers to the process of creating in the minds of consumers real and imaginary product differences associated with an industry's output. For example, the auto industry produces and sells a product that is highly differentiated. Consumers view Fords as being quite distinct from Chevrolets. Indeed, the many options available on a typical automobile mean that even two cars of the same make and model will typically have distinctive features such as color, interior design, and varying mechanical options (air conditioning, automatic transmission, etc.). Product differentiation can also be based on the purely subjective preferences of consumers. A good example would be the long standing preference for cane sugar over beet sugar, even though the two products are chemically identical. Producers may also use advertising to make their product seem preferable over another. However, much product differentiation is associated with real and important differences in the nature of product offerings, and it has the effect of creating greater choice for the consumers in what kind of product they buy and how much they will pay for it.

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[1]The actual behavior of utilities in this area is difficult to document. The belief that at least some utilities have operated in such a manner is as common in the regulatory community as are denials by utility representatives that their own companies have ever engaged in such a practice. Systematic evidence on the subject seems to be lacking.

For a long time in the United States electricity has been differentiated on the basis of the voltage level at which service is provided. Utilities have traditionally offered several distinct types of electric service (i.e., industrial, primary, and residential), based roughly on the voltage level at which the customer can be served.

Recently, the adoption of time-of-use pricing of electricity in some service areas has allowed further differentiation of a utility's product. To a large extent the usefulness and hence value of electricity to consumers depends upon the time at which it is consumed. A kilowatt-hour of electricity provided from 3 a.m. to 4 a.m., for example, is usually not a good substitute for a kilowatt-hour provided from 3 p.m. to 4 p.m. Similarly, the cost of producing each of these kilowatt-hours differs greatly from that of the other. Seasonal and time-of-day rates recognize electricity as a product that is differentiated on the basis of the time it is produced and consumed.

The concept of interruptible electric service is another means for utilities to further differentiate their output. This differentiation is based on the reliability level at which electricity is received. With an interruptible service option, customers are offered the opportunity to choose a service reliability appropriate to their needs, presumably at a rate lower than that charged for regular (firm) service.

Value-Based versus Cost-Based Pricing of Interruptible Service

In the past, interruptible service options have been offered by utilities at rates lower than those charged for regular service. Most of these have taken the form of individually negotiated contracts between the utility and one or more of its large industrial users. These special contract services were often created to induce potential high-volume, high-load-factor customers to use utility-generated electricity as their primary energy source, rather than self-generating their electricity or using some competing energy form such as fuel oil or natural gas. As implied by the existence of individualized service contracts, the price of this interruptible electricity was negotiated and was usually based on the value of the service to the customer. For the industrial customer with potential for self-generation, for example, the finally negotiated price would lie somewhere between the utility's own running costs and those the customer could expect to incur if he were to produce the electricity himself. With the utility's more efficient, large central generating stations, presumably the latter would be greater than the former. Therefore, the interruptible contract based on value-of-service is an arrangement under which both the utility and the industrial customer can benefit.

Provisions of the PURPA and the general concern of ratemaking authorities about setting equitable utility rates, however, have brought cost-of-service principles to the forefront in discussions of electric ratemaking. The PURPA Section 111 ratemaking standard for interruptible service, for example, states:

> Section 111 (d) (5) INTERRUPTIBLE RATES - Each electric utility shall offer each industrial and commercial customer an interruptible rate which reflects the cost of providing interruptible service to the class of which such customer is a member.

What we present in this report is an exploration of one approach to pricing interruptible service on the basis of the costs of providing that service, the marginal cost approach. Not all agree that marginal cost is the appropriate standard to use when calculating cost-of-service, but marginal costing clearly lies on the cost-of-service rather than value-of-service side of approaching this particular ratemaking problem.

Load Management, Capacity Planning, and the Reliability of Interruptible Service

Effective utilization of interruptible service by utilities in their overall load management program can provide excellent opportunities for the realization of two of PURPA's ratemaking goals--efficiency in utility operations and conservation of scarce energy resources. If interruptible rates are properly set at the cost of providing interruptible power, the third of PURPA's goals--equity toward ratepayers--will also be served. More specifically, providing an interruptible rate and strategically shedding the load of customers who select it can result in the postponement of expensive capacity additions and the conservation of scarce and expensive peaker fuel. Offering an appropriately reduced rate to customers who select the option can also provide an incentive for customer shifting of unnecessary peak loads to off-peak hours, thus improving system load factor and promoting utility efficiency.

While having an interruptible rate ideally can result in the above favorable developments in utility operation, past experience with interruptible rates suggests that, in some cases, the ideal has not been realized. Despite being classified as "interruptible," many customers have seldom had their electricity cut off. At the same time, the utility has continued to build new generating capacity. One is tempted to conclude in these situations that some of this capacity may have been planned to meet interruptible loads. This practice, where it exists, furthers neither utility efficiency, conservation, nor equity.

One solution to this problem is for the state utility commission not to approve for inclusion in the utility's construction plans those capacity additions associated with meeting interruptible customer's load. Not permitting such raising of capital would in a way solve the problems of equity and efficiency. Planning no capacity for interruptible service, however, creates another problem: the threat of very low or highly unstable reliability levels for interruptible service customers.

When a utility plans no capacity additions to serve the needs of interruptible customers, the frequency of interruption for interruptible customers can become high and/or irregular, depending on the number and load patterns of customers selecting the option, and the coincidence of their demands with the regular, assured-service customers. For some interruptible customers (e.g., those who can reschedule most consumption to off-peak hours), these frequent or unpredictable patterns of interruption on peak may be of no concern. Their main interest, due to high volume consumption, is in receiving a lower rate. Other potential interruptible customers may be interested in a somewhat reduced rate and could accommodate occasional interruptions of service, but only relatively infrequently and only when the frequency, timing, and duration of interruptions could be predicted with some reasonable degree of certainty.

One approach to resolving this problem is to create two classes of interruptible service, one for which some utility generating capacity is planned (Class I) and a second for which there is not (Class II). Each faces a different rate. For Class I, a lower than normal reliability level would be specified and generating capacity built to meet this level. Providing power to Class I interruptible service at a reliability level lower than regular service would result in a lower cost of service and preserves the potential for a reduced rate. Specifying a minimum for Class I reliability, however, also resolves the problem of too frequent or unstable patterns of service interruption. Class II interruptible, on the other hand, would have no minimum reliability and would be served only by the utility's available idle capacity. This preserves the opportunity for power consumption at the lowest possible cost.

Creating such interruptible service options to go along with regular (firm) service, however, can create some formidable costing problems for the cost-of-service analyst, not to mention the initial problems posed for the utility's marketing department in selecting the proper reliability levels at which service should be offered.

The Economics of System Reliability and Interruptible Electric Service

The reliability of electricity supply systems and selection of optimum plant capacity have been subjects of increasing professional interest among utility engineers and economists in recent years. Much of their work has dealt with the problem of determining the optimum plant capacity that a utility should construct to generate electricity. The optimum capacity of an electric utility refers to the plant and equipment that allows the utility to serve its customer load at the lowest possible cost, taking into account the costs associated with power outages. Optimum capacity depends not only on the magnitude and pattern of customer load but also on the desired reliability level of electric service.

Many utilities use a "loss of load probability" (LOLP) of one-day-in-ten-years as a target for system-wide reliability. Use of this standard means that the total amount of time that a utility would be unable to meet customer demand would be one (24-hour) day in a ten-year period. This level of reliability requires that the utility build and maintain some generation capacity that is used relatively infrequently. Utilities in other countries, such as France and Great Britain, typically maintain electric service reliability levels considerably lower than those in the United States. The U.S. typically experiences a loss of 1.75 hours of electrical service per customer per year. France and Great Britain experience a 6 hour and 17.5 hour annual loss per customer, respectively.[2] This high level of reliability of electrical service in the United States might be admirable were it not for the fact that maintaining it is quite expensive.[3]

Michael Telson has attempted to estimate the social costs (e.g., lost industry output, spoilage, etc.) associated with electric outages. He found the social costs to be well below the costs of the additional plant

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[2]Michael Telson, "The Economics of Alternative Levels of Reliability for Electric Power Generation Systems," Bell Journal of Economics, (Autumn 1975), pp., 679-94.

[3]U.S. Congress, House Subcommittee on Energy and Power, Committee on Interstate and Foreign Commerce, Are the Electric Utilities Gold Plated? A Perspective on Electric Utility Reliability, Congressional Research Service, Library of Congress, 96th Congress, 1st Sess., April 1979 (Washington, D.C.: U.S. Government Printing Office, 1979). For a look ahead at the expected future of utility service reliability given

capacity needed to avoid the outages.[4] Using a quite different technique for estimating the social costs of an outage, Munasinghe and Gellerson found that the power system of Cascarel, Brazil could realize substantial savings by choosing a lower level of reliability than is traditional, and yet still maintain a satisfactory level of service reliability.[5] In this study, the cost of power failures to society includes the costs of interruption of production in other industries, spoilage, and the disruption of leisure time activities by households. Indeed, the loss of leisure time activities is considered the chief outage cost for residential consumers according to Munasinghe and Gellerson.[6]

In sum, the work of Telson and Munasinghe and Gellerson suggests that, from an economic perspective, the traditional reliability levels of electric utilities may be excessive (i.e., the cost of very high reliability may exceed the costs that would be imposed on society by an outage). The ideal reliability level and hence the optimum capacity of the utility, they suggest, requires comparison of the social cost of outages with the cost of maintaining given levels of reliability in electricity supply.

The well known Averch-Johnson thesis holds that regulated public utilities have an economic incentive to increase their rate base through excessive investment in plant and equipment.[7] Additional theoretical

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alternative demand and supply scenarios, see: U.S. Congress, House Subcommittee on Energy and Power, Committee on Interstate and Foreign Commerce, Will the Lights Go on in 1990? Congressional Research Service, Library of Congress, 96th Congress, 2nd Session, August 1980 (Washington, D.C.: U.S. Government Printing Office, 1980).

[4]Telson, op. cit., pp. 685-690.

[5]Mohan Munasinghe and Mark Gellerson, "Economic Criteria for Optimizing Power System Reliability Levels," Bell Journal of Economics, (Spring 1979), pp. 362-3.

[6]Ibid., p. 356.

[7]H. Averch and L. Johnson, "Behavior of the Firm under Regulatory Constraint," American Economic Review, (December 1962), pp. 1053-69.

support for the view that a rate-of-return regulated monopoly may tend to choose levels of reliability in electric service which exceed the socially optimal level has been provided by Crew and Kleindorfer.[8] Empirical evidence bearing on the general form of the Averch-Johnson hypothesis is mixed,[9] but the results of reliability studies performed to date suggest that the costs of maintaining reliability levels traditional to U.S. utilities may exceed the economic benefits derived by consumers.[10]

Creating an option of interruptible electric service has the advantage of allowing consumers to participate directly in the choice of the system's total reliability level. As more customers opt for interruptible service, less total capacity is required by the utility. With lowered reliability, of course, may come reduced capital expenditures. Properly priced, interruptible and regular service options give correct price signals to consumers regarding the capacity cost implications of their reliabilty demands, and allow customers to decide the utility service reliability level that they both want and are willing to pay for. Customers who want highly reliable electric service are permitted the option of purchasing non-interruptible electric service exclusively, but they also will be required to pay a price reflecting the costs associated with providing it.

Cost based pricing of interruptible electric service has received attention only recently. Marchard[11] has developed a model of socially optimal (marginal cost) pricing of electric service supplied at alternative levels of reliability. Unfortunately the model does not take into account the correlation of the electricity demands of individual subscribers (e.g., hot weather may increase the electric demands of many consumers simultane-

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[8]M. A. Crew and P. R. Kleindorfer, "Reliability and Public Utility Pricing," American Economic Review, (March 1978), pp. 38-9.

[9]Daniel Z. Czamanski, et al., Regulation as a System of Incentives (Columbus, Ohio: The National Regulatory Research Institute, 1980).

[10]Telson, op. cit.; and Are the Electric Utilities Gold Plated?, op. cit.

[11]M. G. Marchard, "Pricing Power Supplied on an Interruptible Basis," European Economic Review, (July 1974), pp. 262-274.

ously).[12] This deficiency suggests that a complete theoretical solution to the problem of interruptible electric pricing has yet to be offered.

A recent article by Panzar and Sibley develops a model that incorporates another approach to the problem of pricing electric reliability.[13] Under the Panzar-Sibley model, consumers of electricity are permitted the option of buying a fuse that sets a ceiling level on their electric demand. Each consumer thereby chooses his own level of reliability in the process of fuse selection. Fuses are priced according to the utility's marginal cost of capacity. One difficulty with this self-rationing approach is that it does not account for the diverse timing of customer loads. An individual subscriber may exceed his allotted fuse capacity and be cut off from further consumption during an off-peak time. Such rationing of consumption is manifestly inappropriate when idle generation capacity exists.

In conclusion, a review of the current economic literature indicates that considerable work remains to develop an acceptable, operational method for pricing interruptible service in a marginal cost framework. An attempt to develop such a method appears in chapter 5.

Recent State Public Utility Commission Rulings

Information on states' consideration of the PURPA interruptible service standard from sixteen state public utility commissions was available at the time of this writing. These states are Arkansas, California, Colorado, Connecticut, Florida, Illinois, Kansas, Massachusetts, Michigan, New York, North Carolina, North Dakota, Ohio, South Carolina, Vermont, and Virginia.

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[12]Ibid., p. 273.

[13]John C. Panzar and David S. Sibley, "Public Utility Pricing under Risk: The Case of Self Rationing," American Economic Review, (December 1978), pp. 889-95.

Of these sixteen states, seven have some form of interruptible service option in place for industrial and commercial customers. In addition, at least five of the sixteen states have approved some form of interruptible residential load-control option. Eight state public utility commissions have ordered studies of the industrial interruptible service option and its feasibility, while six state commissions have initiated studies of residential load control.

The industrial interruptible service offered by the major Michigan utilities provides an interesting example of interruptible rate design. The minimum reliability level for this service is described in terms of a maximum number of hours of interruption permitted per year (e.g., 600 hrs. or 1,000 hrs.) and a maximum of 14 hours of interruption per day. The ratio of the maximum possible hours of interruption per year to the number of peak hours per year, multiplied by the regular service demand charge yields the demand charge discount permitted to interruptible industrial customers. An attractive feature of this method is its operational simplicity.

Two of the perhaps better known residential interruptible power service options offered by regulated utilities are in Arkansas and Vermont. The special interruptible air conditioner rate approved by the Arkansas Public Service Commission allows Arkansas Power and Light to offer residential customers with central air conditioning an interruptible service option.[14] Radio signals are used by the utility to interrupt consumption. Participating consumers are granted a monthly credit per kva of air conditioner compressor capacity. In Vermont, the Green Mountain Power Corporation offers residential customers a five-dollar-per-month credit for agreeing to water heater load control using a ripple control system.

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[14]Raymond W. Lawton, et al., Energy Management and Conservation in Arkansas, NRRI-78-1 (Columbus: The National Regulatory Research Institute, 1978).

For a review of some of the more interesting utility experimental programs currently underway involving interruption of customer load, see the recent article in Public Utilities Fortnightly by Reinbergs and Harlan.[15]

The Perspective of Industrial Consumers

In general, industrial consumers are on the record as favoring introduction of interruptible rates.[16] At the same time, there seems to be little support for marginal cost pricing of electricity within this influential consumer group.[17] Hence, an interruptible rate based on marginal cost pricing principles may encounter some opposition from industrial consumers. However, the lower net cost of power available to many industrial customers through introduction of cost-based reliability option(s) may reduce much of their criticism. Potential cost savings may be especially magnified in utility service areas where the interruptible option(s) are offered as alternatives to mandatory time-of-day rates for large users.

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[15] Mo Reinbergs and Kenneth M. Harlan, "Problems with Direct Load Control by Electric Utilities," Public Utilities Fortnightly, January 3, 1980, p. 21.

[16] Jay B. Kennedy, "Load Management: Good Ideas or Not?" ELCON Report (Winter 1979), p. 2.

[17] Ibid., p. 5.

CHAPTER 5

METHODS FOR COMPUTING THE MARGINAL COST OF INTERRUPTIBLE SERVICE AND CONVERTING THESE COSTS INTO RATES

As already suggested in our introduction to interruptible ratemaking, the problem of defining interruptible service and tracking its system costs may be made a little easier if one considers it from a variable service reliability perspective. Since regular electric service in the United States presumes a comparatively high service reliability, interruptible service can be defined through the process of selecting appropriately lower level(s) of reliability that meet candidate customer requirements. The costing problem for interruptible service then largely centers around determining the utility capacity expenditures necessary to meet these reliability requirements. There are also, of course, energy cost differences related to peak and off-peak consumption and customer-related metering and load-control device costs that have to be considered in setting a cost-based interruptible rate. However, determining the costs of generation, transmission, and distribution facilities necessary to provide service at prescribed reliability levels is the most challenging costing problem in calculation of the marginal costs of interruptible service.

As a preface to presenting a method for calculating the marginal costs relevant to setting interruptible rates, it may be helpful to consider first the problems of capacity planning and electric service reliability as they relate to providing this type of service and determining its costs.

Capacity Planning, Service Reliability, and Interruptible Service

Perhaps due to the value-of-service pricing tradition in interruptible service contracts, the cost impact on the utility of providing this service at varying levels of reliability has received little attention. Large-volume interruptible customers usually have a reduced demand charge as part of the interruptible rate, compared to that of regular, firm service, but detailed cost justifications for these reductions are seldom offered.

Since utility capacity normally used to serve the interruptible customers' load may be also used on occasion to serve regular service load (during periods of interruption), the capacity planning and costing processes are complicated beyond the standard case in which the service reliability of all customers is homogeneous. In order to prevent the frequency of service interruptions from becoming intolerably high, utilities may need to set aside some capacity to serve interruptible load. It is also clear, however, that some utility capacity cost savings may result from having interruptible load as an additional reserve for meeting regular service demand during extreme system peaks. Utilities may use different decision rules for determining when to meet and when to shed these incremental demands,[1] but the impact of interruptible service class demand on the system's need to incur marginal capacity costs depends basically on two factors:

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[1]Decision rules are needed for both interruptible class and individual customer load shedding, but we are referring to the former. For example, a utility may decide that it will begin to shed interruptible load as soon as operation of the system's peakers are required. This may be a good rule when a utility is concerned primarily with saving on consumption of peaker fuel. Another utility may decide that it will shed interruptible load when it has to buy power to meet load. Still another utility may interrupt as an alternative to building new capacity. Any of these rules may be appropriate, depending on utility circumstances. In this report, we assume that the utility sheds interruptible load when total system load, including interruptible, exceeds total available capacity. We assume further that the company stops interrupting and buys or builds additional capacity to meet interruptible demand only when further interruption would violate the maximum amount of interruption provided for in the customer's tariff or service contract.

1) the coincidence of this demand with regular, assured service peak demand; and
2) the service reliability specified in the interruptible tariff or service contract.

One could reasonably expect that the reliability needs of customers who may be candidates for interruptible service could actually be quite different from each other; i.e., their tolerances for interruptions according to timing and duration may vary markedly. As we have already suggested, this situation may require the creation of more than one class of interruptible service, each with a different service reliability level and, presumably, cost of service.

Another problem that arises in calculating the costs of utility capacity required to provide interruptible service is that these costs are composed of two parts: generation, and transmission and distribution (T&D). Maintaining customer service reliability requires not only sufficient generating capacity to meet customer load, but also sufficient capacity in high voltage transmission lines, distribution substations, and line transformers to handle the load.[2] In practice, most customers are rarely if ever interrupted for lack of transmission and distribution capacity, since the utility's network provides multiple routes for reaching most customers; but most utility outages that do occur in the United States are due to T&D failures.[3] Industrial interruptible customers, moreover, are normally large-volume consumers, and they may not be uniformly distributed geographically over the utility's T&D network. Several industrial interruptible customers located along the same transmission line, for example, may be interrupted more frequently due to T&D failure than an industrial interruptible customer located in a primarily residential area.

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[2]The probability of an interruption is equal to the probability of an interruption due to generation capacity failure, plus the probability of transmission capacity failure, minus the probability of the simultaneous independent failures of both generation and transmission capacity.

[3]U.S. Congress, Are the Electric Utilities Goldplated?, op.cit., Table 1; for complete citation, see Chapter 4, footnote 3.

In this sense, interruptible service customers may compete for the use of the excess transmission and distribution capacity serving their particular geographic area if insufficient capacity is planned and built for their use. The process of planning and determining the cost of this T&D capacity is complicated by the introduction of reliability levels other than that normally assumed for regular service. How much sharing will go on between interruptible and regular service? How frequently will interruptible service have to be interrupted due to T&D failure for given amounts of T&D capacity investment and customer load?

A first step toward solution of these costing problems is to make explicit the reliabilities at which services are to be offered. For the sake of simplicity, we examine here the case in which two classes of industrial interruptible services are offered--Class I and Class II. Class I interruptible customers would be charged for enough generation and T&D capacity to maintain their reliability at some target level. Class II interruptible service would have no capacity planned for it or charged to it, and its reliability would be left unspecified. Such a reliability ordering of customers would result in Class II interruptible load being shed first as total system demand exceeds total system capacity, Class I interruptibles second, and regular service customers last. In some systems, Class II interruptibles could expect a virtual certainty of interruption during certain peak demand hours. The actual number of hours of interruption would depend on the system coincidence and volume of demand by the individual Class II customer, the coincidence and volume of demand by other Class II subscribers, as well as the demand of regular and Class I interruptible customers. The minimum reliability of Class I customers would be sufficiently lower than that of regular service customers so that substantial capacity savings could be realized by the utility. The reliability would be sufficiently high, however, that the frequency of interruption for Class I would be relatively rare, unlike Class II subscribers, and the conditions leading up to such interruptions could be easily identified.

In this way, Class I interruptible service would meet the needs of customers who are sensitive to the price of electricity, but who are also unable to accommodate frequent or unpredictable patterns of interruption. For these interruptible customers in the industrial class, electricity expenses may be such a significantly large portion of total production costs that a reduction in rate would be worth an occasional rearrangement of production schedules. However, the costs of labor or fixed overhead, variable seasonal demand, or the nature of their production processes may preclude frequent or unpredictable power interruption. From the utility's perspective, the demand of Class I customers will be served most of the time by under-utilized capacity, which is only occasionally needed for regular service demand. In addition, some additional generating capacity may have to be built to keep these customers' annual loss-of-load probability (LOLP) below a certain maximum as the volume of their class demand rises (which is another way of saying that their service reliability will be maintained at a target minimum). The lower capacity charge and assurance of long-run stability of reliability levels may act to attract some large users of electricty to this rate.

Certain other firms, which would make up Class II, may be extremely sensitive to electricity's price and relatively insensitive to its reliability, especially during the utility's peak periods. Both the minimum reliability level and associated capacity charge assessed Class I customers may be unnecessary for this class of consumers. If lumped with those selecting a Class I type service, they could be charged for more reliability than they actually need. For this reason, a Class II interruptible rate is proposed that includes no capacity charge and that sets no lower limit on service reliability. Class II customers would be served by only the utility's capacity left over after it has met regular and Class I demand. The reliability of Class II service would also be allowed to vary significantly over time depending on the relative demands of regular service, Class I, and other Class II interruptible customers.

In summary, Class I interruptible service would offer large users of electricity the option of receiving service at a lower, but assured, minimum level of reliability with a corresponding reduction in the usual capacity charge. Class II interruptible service would offer customers a tariff with no capacity charge in return for service with virtual certainty of some interruption during peak periods.

Calculating Marginal Cost Based Rates for Class I and Class II Interruptible Service

This section presents methods for calculating the marginal costs of generation capacity for interruptible service and a discussion of the marginal transmission and distribution, energy, and customer components of interruptible rates. The subsection on generation capacity presents two methods for calculating a marginal-cost-based generation capacity charge for the Class I interruptible customer class. The first is an idealized method, similar in structure and purpose to the idealized method presented in chapter 3 for calculating utility avoided costs of cogeneration supply. Like the method in chapter 3, it ignores limitations of data availability, costs of data acquisition, and availability of resources required to make computations. The second is a simplified method, also similar to the simplified method presented in chapter 3, that may prove a more practicable approach for ratemaking in many situations.

Marginal Costs of Generation Capacity

An Idealized Method

An idealized approach to the problem of calculating the marginal cost of generating capacity required to serve Class I interruptible customers involves forecasting utility demand and modeling its capacity expansion processes, once with Class I interruptible customers on the system and once without them. The basic procedures required to execute such a method are presented below in a series of seven steps.

Step 1. Forecast the demand of the utility's regular, assured service customers over the duration of the utility's capacity expansion planning period.

Step 2. Run a system capacity expansion planning model to determine the present value of the total cost of generation capacity and system operation required to meet this forecast of regular service demand.

A capacity expansion planning model chooses the least cost means for a utility to meet its forecasted demand. The output of the run should include a schedule of plant additions, described in terms of their rated capacity in kilowatts, and the present value of the total capital and operating costs for meeting load over the expansion plan.[4]

Step 3. Forecast Class I demand for the period during which rates will be in effect. Assume this to be a permanent demand increment that extends through the utility's planning period.

Assuming Class I demand for the rating period to be a permanent demand increment is convenient for calculating the long-run marginal (capacity) cost consequences for the utility that result from having these customers on the system.[5]

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[4]We assume that the capacity expansion planning model will calculate these present values. For a discussion of how to calculate the present value of a future expenditure, consult a standard engineering economics text; e.g., H. G. Thuesan, W. J. Fabrycky, G. J. Thuesan, Engineering Economy, 4th edition (Englewood Cliffs, N.J.: Prentice-Hall, Inc., 1971), pp. 105-8.

[5]Calculating the long-run cost of a demand increment occurring in the present is a process that is always somewhat tentative. This is the case because of the inconsistency between the practical requirements of expanding utility capacity and the limitations on our ability to forecast future demand. Forecasting economic events is a process fraught with uncertainty, especially as one attempts to extend that forecast more than just a few years into the future. This is as true for forecasting demand for electricity as it is for making any other type of economic forecast. The lead time requirements for electric power plant siting, licensing, and construction, however, require the forecasting of electric demand at least ten years into the future. Since power plants are typically considered to have a thirty-year useful service life, a utility's decision to invest in the construction of a new plant as the least cost option for meeting an expected increment in load also requires the assumption that there will be sufficient demand over the whole life of the plant to justify the expend-

Step 4. Run a system expansion planning model on the combined forecast of regular and Class I interruptible service demand to determine the present value of the total cost of generating capacity and system operation required to meet this forecast of combined demand.

It is assumed here that the model is capable of planning capacity expansion to meet demand at different levels of reliability. The input for the run includes the respective reliability levels of regular and Class I customers. The output of the run is a utility expansion plan that requires no more interruption of Class I customers than is specified in their tariff or service contract, while at the same time meeting the demand of the regular service class at its required reliability level. The expansion plan should be expressed in terms of a schedule of plant additions, described in terms of their rated capacities in kilowatts, and the present value of the total capital and operating costs required to meet load over the expansion plan.

Step 5. Subtract the results of Step 2 from Step 4, which yields the difference between the present values of the total costs of the two expansion plans.

Note that differences in operating costs of the two plans are automatically taken into account by this procedure. This includes the "fuel savings" often considered in calculating marginal capacity costs.

Step 6. Annualize the Step 5 result.

Assuming the present-value, incremental cost of utility generating capacity needed to serve Class I interruptible customers will not be

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iture. (Any accelerated depreciation schedule helps to reduce the uncertainties associated with recovering such investments and, if present, may be taken into account in ratemaking for the service requiring them.) We treat the Class I demand as permanent so that, when it necessitates the addition of a new plant, it can be treated as though it extends throughout the plant's useful life.

collected in a one-time lump sum payment, this step is needed to find the annual installment on this cost attibutable to the service of Class I customers. Annualized cost can be obtained according to the following general formula.

$$PVAC = PVTC \left(\frac{IR}{1 - (1+IR)^{-N}} \right)$$

where:

PVAC = present-value annualized cost;

PVTC = present-value total cost;

and the expression in parentheses is an annuity factor in which:

IR = interest rate;

N = number of years over which the cost is to be annualized.

With a demand increment assumed to be permanent, one can take N to equal infinity (∞).[6] When doing so, the formula reduces to the simple expression:

$$PVAC = PVTC\ (IR)$$

Step 7. To obtain a unitized (marginal cost) measure of this annualized incremental cost of generating capacity, divide the Step 6 result by the

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[6] If the demand is not considered permanent, a finite value for N may be appropriate. If the interruptible demand is assumed to exist for a finite time, e.g., 30 years, then a 30-year annuity repayment of the total cost could be used. At a 10 percent interest rate, the difference in annuity factors would be 0.1000 (for $N = \infty$) versus 0.1061 (for N = 30). In practice, any demand should be considered permanent if it extends beyond the utility's forecasting horizon. Without particular information that interruptible demand is temporary, it should be treated in the same manner as regular service demand with regard to this aspect of cost analysis. That is, whatever repayment period (N) is used for calculating regular service annuity payments should also be used for interruptible customers.

annual amount of electricity consumption by Class I interruptible customers.

The correct divisor for obtaining this annualized, long-run marginal cost of generating capacity is the total kilowatt-hour sales to Class I interruptible customers during the year to which the rate is to apply. The ratemaker's choice of consumption unit (kilowatt-hour or kilowatt), however, will ultimately depend on the billing unit to be used in the tariff or service contract. If periodic readings of a demand meter are used for collecting demand-related capacity charges, then some forecast of the (uninterrupted) Class I demand during the rating year must be used. In practice, such a forecast would be extremely difficult to obtain with any accuracy, suggesting that kilowatt demand indicating meters may not be appropriate for use with interruptible customers if they are to face rates calculated by the method presented above. Such meters indicate only a customer's maximum demand during the billing period. This is used as a proxy for his peak-coincident demand. Because interruptible customers are most likely to be interrupted during the system peak, readings of maximum demand from demand meters are probably of little value for ratemaking in the case of these customers. Spreading their annual capacity costs over their annual sales in kilowatt-hours is a better procedure.

While an accurate forecast of uninterrupted peak load by interruptible customers may not be possible in practice, data on recent loads of this type may be available. In this case, the following simplified method for calculating marginal capacity costs may be used. This method does not yield a theoretically precise calculation of the marginal cost of capacity associated with increments in Class I interruptible demand. However, it does result in an approximately correct price signal of the cost of meeting new interruptible demand relative to the cost of meeting new regular service demand, based on some recent assessment of these relative costs. In addition, it can be used with a kilowatt demand-indicating meter.

A Simplified Method and Illustration

Detailed forecasting of utility demand by customer class and modeling utility system expansion processes, especially when class service reliabilities are not homogeneous, are ambitious undertakings requiring data, computer, and personnel resources that not all state commissions possess. A simplified approach that may approximate results from an idealized method is therefore desirable. One such simplified method for calculating a utility's long-run marginal cost of generating capacity was presented in chapter 3 (for discussion of the MARGINALCOST approach, see "Purchases of Energy and Capacity: A Simplified Method"). It dispenses with forecasting demand and reoptimizing system expansion plans. Instead, it calculates an annualized, present-value dollar-per-kilowatt measure of long-run marginal cost of generating capacity based on the costs of delaying the utility's existing schedule of capacity additions by one year. Unfortunately, the MARGINALCOST method also assumes a homogeneous service reliability for all customer demand; i.e., it assumes all simultaneous increments in demand will be met by the utility at the same LOLP, and it does not directly address the question of what impact the utility's ability to interrupt certain customers at peak times may have on its need to incur this marginal capacity cost.

One way to acknowledge the capacity-related benefits of being able to interrupt a customer class at times of peak load is to measure the relative contribution of the various customer classes to the creation of the utility's peak demand period. Pricing at marginal cost, one can then determine the total annual demand-related generation charges for each customer class based on its uninterrupted demand at system peak. Using such a method requires that some care be taken in identifying the peak period. The process involves more than simply identifying the high point on the utility's hourly load curve. One must also determine that the peak period selected is a time when all possible Class I and Class II interruptible load has been shed by the utility, except that portion of Class I demand that is required to meet the reliability target of this group. Most of the time, this period will coincide with the high point on the utility's annual load curve. It can be the case, however, whether because of imprudent interruption practices, unanticipated seasonal consumption, or unexpected frequencies of forced outages, that the time of system annual peak load is not the time when the Class I service reliability requirement is creating the need for new capacity.

A convenient indicator to use for selecting the peak relevant for the calculation of Class I peak responsibility may be the observable pattern of Class I customer class interruption. The period of highest system demand with the highest amount of Class I load being interrupted is most likely to be the time when the system's ability to provide power is under maximum stress. The relative contribution of Class I customers to this maximum stress period is one measure of their relative contribution to the utility system's need to expand capacity and incur marginal capacity costs. Given the reliability ordering of customers already suggested, it is also assumed that this period would be identifiable as having no Class II interruptible customers consuming power, since by definition their usage is always served by only available generating reserves.

The duration of this period for measurement of Class I responsibility should also be defined with care. Defining the period too narrowly could allow some momentary interruption error to provide a false indication of system stress. Defining it too broadly, on the other hand, by the inclusion of hours with less intense demand pressure, could overestimate the relative contribution of Class I customers to the utility's period of maximum reliability stress. Some judgment by the analyst will be required in determining the exact number of hours, but the optimum length of time for the period will probably be not less than one hour and probably not more than three or four.

In order to illustrate how a Class I interruptible capacity charge may be computed with this method, let us assume that this period of maximum stress on utility capacity has been identified and that the results of our customer class consumption (kW or kWh) must be forecasted for each period over which capacity charges will be collected, depending on the form of the rate (\$/kW or ¢/kWh) for collecting each customer class' total annual capacity charges.

In this illustration, we assume that time-of-use pricing is not being used and we calculate a dollar-per-kilowatt capacity charge.[9] We are assuming that capacity charges are assessed every month according to the reading of a demand meter for each customer. This is not the way charges are made to most customers in most circumstances, except for the company's largest consumers, but doing so here helps one to compare the levels of charges by customer class. Column (4) lists average monthly noncoincident peak demand for the year by customer class. Column (5) presents marginal-cost based monthly capacity charges in dollars per kilowatt by customer class, unadjusted for class diversity factors. They are calculated by dividing the customer class total annual capacity charge by the sum of its monthly noncoincident demands (or average monthly noncoincident demand multiplied times twelve).

The resulting monthly capacity charge for the Class I interruptible service class is \$2.189 per kilowatt, and the charge for the regular service class at the same voltage level is \$6.566 per kilowatt. Remember that the system marginal cost of increased consumption on peak (\$63.96/kW) is the same for both customer classes, but the monthly marginal-cost based capacity charges resulting for each class are quite different. The charges reflect the utility's ability to interrupt Class I customers at the time when the most severe upward pressure on its generating requirements exists.

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[9]Since most utilities in the U.S. do not have time-of-use rates, using the whole year as a homogeneous pricing period corresponds to the ratemaking situation that most face. However, while industrial and other large-volume users are often billed on a dollar-per-kilowatt basis for their measured demand each month, other customer classes usually are not. Dollar-per-kilowatt charges based on anticipated kilowatts of demand are calculated here for each customer class to facilitate comparisons. Cents-per-kilowatt-hour charges can be calculated for any of the classes by dividing the class entry in column (3) by its anticipated kilowatt-hours of consumption instead of kilowatts of demand.

Class II interruptible customers, of course, are not permitted to consume any power during the peak. Their monthly capacity charge is zero.

The approach to calculating marginal-cost based capacity charges presented in this simplified method relies on recent measurements of the responsibility of customer classes for creating a utility's maximum-stress peak period. This approach may be well suited for evaluating the current year's capacity charges from a marginal cost perspective. It may be less well suited for calculating charges that will be in effect in future years. The extent of service interruption for Class I customers may vary greatly from year to year, especially when new generating capacity comes on line or extreme fluctuations in seasonal consumption occur. The current peak load responsibility of Class I customers may provide only a rough indication of their responsibilty in the next year or two.

Transmission and Distribution Costs

Transmission and distribution (T&D) costs are of two types: those that vary with load and those that do not. The transmission and distribution costs that do not vary with the load of interruptible service customers can be estimated, using such standard techniques as the zero-intercept method,[10] and included in the fixed customer charge (see below). Variable T&D costs can be divided further into two types: transmission costs associated with the bulk power supply and the demand-related portions of the customer distribution network cost. Since bulk power transmission facilities are closely related in the way they expand to the expansion of generation capacity, it seems reasonable to allow the demand charge for the bulk power network to hold the same ratios for Class I and Class II interruptible to regular service as the Class I and Class II interruptible generation demand charges (always zero for Class II) have to the regular service generation demand charge. This assumes that the same proportional relationship exists between generation and bulk power transmission capacity

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[10]Czamanski, et al., Electric Pricing Policies for Ohio, op. cit.; for complete citation, see chapter 1, footnote 3.

costs for all of these customer classes. The remaining customer distribution network often involves multiple means of reaching most customers, and it may be the least likely area to display cost savings due to interruptible service. A reasonable simplification, therefore, is to use the same demand charge for this distribution network for regular service and Class I and Class II interruptible service.

Energy and Customer Costs

If the annual load curve of Class I and Class II interruptible customers is known with some reasonable degree of certainty, including patterns of consumption and interruption during peak hours, the marginal energy costs for these customers can be calculated by a method similar to that presented in chapter 3, "Purchases of Energy." However, such an approach ignores the potential benefits to all consumers of reductions in overall utility unit energy costs due to the existence of interruptible load. Since the primary cost reductions associated with interruptible load are likely to be in utility capacity costs, a commission may choose simply to allow the same energy charge for interruptible and regular service customers.

Customer costs for interruptible customers are the same as for regular service customers, except for the additional costs of special meters and load control devices. These special costs may be added to the interruptible customer charge, or they may be included as a rate base item and charged to all utility consumers. The former approach is based on a "causer of cost" philosophy.[11] The latter recognizes the benefits in lowered system energy costs occurring to all consumers as a result of interruptible customers' existence on the utility system, by charging their special customer costs to all who benefit from them.

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[11]If this approach is selected, however, consistency may also require giving interruptible customers a credit in their rate that reflects the overall system energy cost savings attributable to their agreeing to be interrupted. The idealized method for calculating marginal capacity costs presented earlier in this chapter represents one approach to incorporating these running cost savings into an interruptible rate. See specifically Steps 2, 4, 5, and associated text.

Potential Problems and Limitations in Implementing a Marginal Cost Based Interruptible Rate

Efficiency and Conservation

Two of the primary benefits claimed for the marginal cost pricing approach in general are reduced consumption of scarce energy-producing resources and improved load factors in electric utility operations. Both essentially add up to the elimination of wasteful consumption by utility customers and a net reduction in utility production costs. However, problems in utility efficiency and energy conservation related to interruptible service could remain even with the adoption of marginal cost based rates.

For example, one of the economic benefits attributable to a well-constructed interruptible rate is the potential savings in capital equipment and fuel expenditures by the utility associated with improved system load factor. Any rate structure that acts to reduce the expected annual peak demand on the utility's generation and transmission system will tend to reduce capital equipment expansion requirements and expensive peaker fuel consumption, which can result in lower system costs and potentially lower rates.

The cost saving potential of interruptible service will not be realized, however, if the utility is unwilling to allow the reliability of Class I interruptible service to fall to its target level. In this same vein, offering Class II interruptible service will be effective in providing long-run capital savings only as long as the utility expands neither generation nor transmission and distribution capacity on behalf of these customers.

The seriousness of these concerns will, of course, depend on the magnitude of the potential cost savings involved. As the magnitude of interruptible loads becomes larger and the cost pressures associated with utility peak load growth become greater, the need for public utility commission monitoring of the situation increases. The easiest monitoring task involves tracking the frequency and pattern of service interruption of interruptible customers. If the timing and duration of interruptions do not approximately correspond to those anticipated in the contract or tariff, then clearly a commission investigation may be in order. Another part of this commission monitoring process, however, would be to confirm that the correct interruptible service reliabilities have been selected in the first place. A Class II interruptible rate, permitting electricity consumption at the lowest possible cost, would be of little value if too few customers opt for it because the frequency of interruption has become intolerable. Periodic review of customer reliability needs would be part of the monitoring process.

Monitoring the utility's capacity savings due to the management of interruptible load and judging the appropriateness of its expansion plans, taking interruptible loads into account, are parts of a more complicated and long-term monitoring process. The diagnostic tools and procedures required for making such evaluations are included in the presentation of interruptible service costing methods, above. A system expansion plan for forecasted regular service load at its target reliability level yields an estimate of the generating capacity needed to serve this customer class alone. To obtain an estimate of the additional capacity needed for Class I service, one must run an expansion plan for the forecasted combined loads of regular and Class I interruptible appropriate to their respective levels of service reliability. The difference between the two expansion plans provides an estimate of the additional capacity needed to serve Class I load, beyond that already planned for regular service. Comparing these forecasts and estimates with the utility's current expansion plans can provide an indication of the company's performance in holding down capacity expansion costs by use of service reliability options.

In addition to the potential capacity cost savings associated with interruptible rates, there is also a potential for significant savings in fuel costs per kilowatt-hour. Interruptible service can contribute to improved system load factor and change the long-run optimum mix of generation equipment. The proportion of base and intermediate generation equipment relative to peaking capacity could increase as interruptible loads grow, producing an associated decrease in the system's fuel expense per kilowatt-hour. Since the capital cost of base and intermediate load equipment is more expensive per kilowatt than peaking equipment, part of the decrease in fuel expense will be offset by higher capacity costs. Any attempt to credit lower system fuel costs to interruptible customers should not ignore these higher capacity costs. To avoid an essentially arbitrary allocation of fuel and capacity expenses, it may be best to utilize the same energy charge for all customers. Only a highly sophisticated diverse technology model of utility system marginal cost can properly provide for a differential between marginal energy costs of regular and interruptible service.[12] The use of such a model would significantly increase the volume of information needed to produce marginal cost rates.

State utility commissions also need to be aware that the added expense of special metering and control devices used in implementing interruptible service can offset the potential capacity and fuel cost savings associated with adopting this type of rate. This is especially true for small customers whose increased customer costs may exceed the savings in their demand charge. The feasibility of interruptible service of any kind depends crucially upon the cost of metering and load control compared to the utility's savings in capacity and fuel.

The detrimental cost impact of cheating on an interruptible rate is also significant. When interruptible service customers are expected to cut off their own consumption upon notification by the utility, failure to do so will have serious cost consequences for the utilty. Even with electro-mechanical control of customers' loads, the potential for bypassing the

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[12]Michael A. Crew and Paul A. Kleindorfer, "Peak Load Pricing with a Diverse Technology," Bell Journal of Economics 7 (Spring 1976), pp. 207-31.

control system may exist. An appropriate penalty and disincentive for such transgressions might be a charge equal to all interruptible service demand savings that the customer has experienced in the past year. In any case, the penalty assessed for cheating must be sufficiently great to remove any economic motivations for an interruptible service customer to subvert the provisions of his contract or tariff.

Changing reliability of interruptible service, such as that which may result from the "lumpiness" of utility expansion processes, can also create problems for utility conservation and efficiency. Such instability could encourage consumers to opt for interruptible service when its reliability rises and switch back to regular service as the reliability of interruptible service falls. The selection of a target minimum reliability level for Class I interruptible service minimizes the problem for this class by permitting the utility to increase its plant capacity to meet its needs. Even so, large and unexpected shifts in the number of customers using Class I interruptible service may cause the reliability of this service to deviate from its target level in the short run. Class II interruptible service has no minimum target reliability and thus its actual reliability level is likely to vary significantly with any major changes in demand or total reserve capacity of the system.

The simplest solution to any potential switching problem might be to provide for a switching penalty that removes the financial incentive for switching from one reliability level to a higher one. A Class II interruptible service customer who switches to Class I interruptible service, for example, might be required to pay a penalty equal to the Class I interruptible service demand charge for his past year's consumption of Class II service. By the same token, a Class I interruptible service customer who switches to regular service might be expected to forefeit his past annual cost savings by paying a retroactive regular service equivalent demand charge. This charge would equal the regular service demand charge minus the Class I interruptible service demand charge, and it might be applied to the past twelve months of Class I interruptible service consumption.

A related problem can arise for customers who purchase a mix of regular and interruptible service and may want to switch to the more reliable service during an interruption. In this case, the potential capacity and fuel savings associated with interruptible service are foregone when a reduction in interruptible load results in an increase in regular service demand.

There are two alternative solutions to this problem. One is for the utility to require that the hook-ups for each type of service be completely separate. For example, an industrial customer might use regular service for his lighting, Class I interruptible service for air conditioning and machinery operation, and Class II interruptible service for electric furnace operation. Each of these services would be separately delivered and metered. The difficulty with this approach is that it requires the utility to monitor the customers to prevent connection of any piece of equipment to more than one type of electric service. This monitoring could be rather difficult without unlimited access to all aspects of the firm's electrical distribution system, and it may not be cost-effective for smaller users.

An alternative approach is to allow the customer to use his electrical service in any way he chooses but with upper limits placed on his consumption of the more reliable forms.[13] Any customer will have an incentive to utilize interruptible service heavily during months when the likelihood of interruption is small and switch to more reliable service during the system's peak usage months. Placing an upper limit on the peak demand for regular service by a Class I interruptible customer can limit the amount of this switching activity. Similarly, customers who use Class II interruptible service can have an upper limit placed upon their demand for Class I interruptible service. A customer using all three types of service would be required to set upper limits on his consumption of

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[13]John C. Panzar and David S. Sibley, op. cit., pp. 88-95. In fact, inspection of several tariffs has revealed this to be already common practice between some utilities and their large industrial customers.

regular service and Class I interruptible service, with no limit placed on consumption of Class II interruptible service. Demand charges for these customers would be based on the upper limit selected for regular and Class I interruptible service. If excess system capacity exists, consumption beyond these limits could be met through Class II interruptible service.

Equity or Fairness

Offering interruptible service at a rate that reflects the cost of providing that service creates greater consumer choice in the kind of electric service to be purchased. It also provides an opportunity for reducing inter-consumer subsidies in cost-of-service allocations. Without interruptible service options, consumers cannot choose the reliability level of the electric service they purchase. Customers must pay for high reliability at its attendant high price whether they want it or not. Providing electricity at several reliability levels and at prices reflecting their costs, therefore, allows not only greater consumer sovereignty in the energy marketplace, but also can be more equitable in assigning the costs of their own reliability to those who choose to impose them on the system by virtue of their own decisions about reliability needs.

However, some cross subsidies among customers may still remain with the introduction of an interruptible rate such as the one proposed here. For example, the selection of target reliabilities for regular service and Class I interruptible service, if done inappropriately, can cause customer cross subsidies to arise. Setting reliability targets (and thus reserve capacity requirements) too high for either or both will benefit the lower-reliability category(ies) at the expense of the higher one(s).[14] It may also be inevitable that within the interruptible classes some geographic cross subsidies will arise. As discussed in chapter 4, the probability of interruption due to transmission system failure tends to depend upon the

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[14]In the economic ideal, target reliabilities should be selected according to the outage costs of customers. The subject of optimum service reliability is discussed briefly in chapter 4, but generally lies beyond the scope of this report. For further discussion of the economic issues involved, see Munasinghe and Gellerson, op. cit., pp. 362-3.

interruptible customer's geographic location. A cluster of large interruptible customers located along the same part of the transmission system may be interrupted more frequently than an interruptible customer located in a primarily residential area. Therefore, the cost of maintaining the same target transmission reliability for all Class I interruptible service customers may not be the same. The fact that some Class I customers may require more transmission equipment than others means that some Class I customers may be required to subsidize the higher transmission requirements of the others. To avoid adding costly geographic complications to the costing and ratemaking process, a commission may decide that it is preferable to permit this cross subsidy to exist. Note that since Class II interruptible service customers are not guaranteed and do not pay for any minimum target reliability, geographic differences in reliability within this class imply no cross subsidies.

Unexpected patterns of reliability consumption can also cause temporary cross subsidies to arise between the customer classes. The idealized approach to the estimation of the capacity costs of regular and interruptible service is based upon forecasts of the demand of regular and Class I and interruptible service customers. If these forecasts are proven inaccurate, the capacity costs associated with each will be estimated inaccurately. For example, if Class I interruptible service is more popular with industrial customers than expected, the capacity charge for Class I interruptible service may be too small, and regular service customers would be, for some time at least, subsidizing the plant and equipment capacity needs of Class I interruptible customers.

Periodic observation of the demands of regular service and Class I interruptible service customers during peak periods can provide an indication of the accuracy of the load forecasts used in estimating their capacity costs. If regular service customers are observed never to have peak demands that utilize all of the capacity planned for them, it is likely that the capacity charge for regular service is too large. Under this condition, interruptible service customers are receiving an implicit subsidy. If, on the other hand, the regular service customer class has peak demands that regularly utilize more capacity than planned for its use, then the capacity charge for regular service customers is too small and regular service is being subsidized by Class I interruptible.

Ideally, estimates of capacity cost responsibility should be updated on a regular basis (e.g., annually) using revised load forecasts and system expansion plans. This is especially true when interruptible service options are newly introduced. When the same reliability options have been available and in operation for a number of years, the pattern of customer choice and performance regarding service reliability will be better known and present few forecasting problems.

Some of the conservation and efficiency problems associated with customers' wholesale switching from one reliability level to another were discussed in the preceding section. Apart from these conservation and efficiency problems, certain customer inequities also can result from switching. For example, lumpiness of investment in plant and equipment for utilities with relatively small markets occasionally may cause available capacity to exceed the estimated total capacity necessary for the service of regular Class I interruptible loads. The opening of a huge new base load facility, for example, may create temporary excess capacity so that for a time the reliability of all forms of service is quite high.[15] Obviously a large cross-subsidy incentive will exist under these circumstances for customers to switch to interruptible service until the growing demand for electricity catches up to this excess capacity. During these periods, the utility may want to warn new interruptible customers that their switching from interruptible service back to regular service will require a retroactive demand charge to recover all or some portion of their demand charge savings since the opening of the new facility.

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[15]In fact, this may be an overstatement of the case since utilities normally enter into contracts for firm power sales to other utilities when not all the capacity of a new plant is needed to serve its own customers' demand.

The general problem of switching subscriptions from interruptible to regular service and back again must be dealt with in some manner if interruptible service is ever to achieve its full benefits. The best solution to the problem is most likely to be to set some minimum term of subscription for a reliability option. The length could be one or several years, depending on utility and customer circumstances. Due to typical seasonal variation in electric loads, one year would seem to be a necessary minimum customer subscription duration to enable any utility cost savings to be realized.

Customer Acceptance

The willingness of customers to accept new electric rates most often depends on the effects of the rates on their electric bills. For example, the industrial sector appears in general to favor reliability differentiation (interruptible rates), but not marginal cost pricing.[16] On the other hand, most residential customers would probably not favor the introduction of reliability options that might erase any existing industrial subsidization of high residential reliability needs, therefore resulting in higher residential rates. In fact, as we have seen, interruptible service rates without a carefully calculated capacity charge could result in regular service customers subsidizing the generation and transmission capacity requirements of interruptible customers or vice versa. The elimination or introduction of any cross subsidies will always make new rate proposals controversial.

The ultimate acceptability of marginal cost based interruptible rates may also depend on another factor: their effect on interstate competition for new industrial plant locations. It is often argued that electric rates which subsidize new industrial customers at the expense of other consumers can serve as an inducement for firms to locate within a state. At the same time, the adoption of interruptible electric service rates that accurately

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[16] Jay B. Kennedy, op. cit., p. 2; for full citation, see chapter 4, footnote 16 of this report.

reflect the utility costs can discourage the location of some new plants within a state, especially when other states offer electric rates with implicit subsidies (e.g., interruptible service with no demand charge and relatively high levels of reliability). From the standpoint of economic efficiency, such subsidies for the industrial consumption of electricity are inappropriate. However, the realities of competition among states for new plant locations on occasion may compel state utility commissions to permit offering such rates.

PART III

MARGINAL COST RATEMAKING FOR BACK-UP SERVICES

CHAPTER 6

INTRODUCTION TO RATEMAKING FOR BACK-UP SERVICES

As the cost of electricity has risen, so has consumer interest in alternative, decentralized power systems. When electricity prices were declining, steam cogeneration, active and passive solar technologies, woodburning stoves, and thermal storage technologies were little more than historical or scientific curiosities to most energy consumers. As energy bills and regional dependence on imported oil have grown, alternative energy sources have become more attractive as long-run strategies for reducing energy costs and increasing energy independence.

Decentralized systems often need a back-up power supply. The cost of obtaining back-up service, in fact, is one important element in evaluating the economic feasibility of decentralized power systems. From an economic point of view, it is important that back-up electric rates which accurately reflect the costs of back-up electricity be established early by utilities. The purpose is neither to encourage nor discourage the development of decentralized systems, but rather to provide correct and reliable price signals to designers and potential investors in these systems regarding the cost of electricity as a source of back-up energy.

It was perhaps with this need in mind that the Congress included in PURPA Section 210 the requirement that electric utilities supply, at the request of qualifying cogenerators and small power producers, interruptible, supplementary, maintenance, and back-up power at nondiscriminatory rates. The FERC, in issuing rules pursuant to this law, has required state utility commissions to set rates for these services that are

1) just and reasonable,
2) in the public interest, and

3) nondiscriminatory in comparison to rates charged to other customers served by the electric utility.[1]

The ratemaking issues and methods for calculating marginal cost based rates for interruptible power, of course, are the subjects of earlier chapters in this report. Supplementary, maintenance, and back-up services are specific types of stand-by (or back-up) power service as variously defined over the years. Because of the potential confusion over exactly what does and does not constitute back-up service, it is important to define carefully the services to be offered in order to accurately estimate their costs.

Definitions of Back-Up Services

In the broadest sense, a back-up customer is any consumer of an electric utility who relies on some source of energy other than utility-generated electricity to fulfill all or some significant part of his regular energy needs, but who retains the option of drawing on the electric utility when his alternative energy source is either insufficient or unavailable. In this broad context, back-up service becomes that power provided by a utility to a back-up customer to satisfy his unmet requirements. Under this definition, solar home dwellers and people who heat their homes with woodburning stoves may have back-up power needs and want to become back-up electricity customers, as, most likely, would industrial steam cogenerators and owners of various types (e.g., hydro or wind) of small power production facilities.

Each of these potential back-up customers may have a need for several different types of back-up service, however, and each type may have different cost consequences for the utility. For example, the industrial cogenerator may have a steam turbine-powered generating facility whose electrical output he consumes on premises to run his electric motors, light

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[1] Federal Register, 45, no. 38, February 25, 1980, p. 12236.

and heat his buildings, etc. Should the boiler, turbine, or generator malfunction, he may want to draw on the electric utility for power rather than discontinue productive operations until the mechanical failure is corrected. The cogeneration power plant manager also must schedule routine monthly maintenance (e.g., eight hours each month) and major system maintenance, typically once per year. During the latter, the generating facility may be down from one to three weeks, depending on the extent of repairs. The cogenerator will want to draw on utility power to some degree during these periods. Lastly, the cogenerator's steam output may be adequate to generate only a part of his plant's total electricity requirements. As a back-up customer, he may want to draw on utility capacity to make up the difference between what his cogeneration system can generate and his total electricity needs.

Back-up power requirements similar to these are likely to exist for residential and other smaller back-up customers. Note that each type of demand may differ from the others in magnitude, frequency, timing, duration, and degree of predictability. Each may require, therefore, separate treatment in the costing and ratemaking processes. During the course of this report we use the term "back-up service" as a collective term. It refers to the electric service or services provided by an electric utility to a customer who uses some source of energy other than the utility to meet all or some significant part of his energy needs and who draws on the utility only when the alternate energy source is insufficient or unavailable. There are three kinds of back-up service that a utility may find itself asked to provide to a back-up customer in this situation. We refer to them as maintenance, stand-by, and supplementary power. Maintenance power is that provided to the back-up customer during scheduled outages of his primary facility. Stand-by power is that supplied during unscheduled outages. Supplementary power is that provided on a more or less regular basis to make up the difference between the customer's total energy needs and that produced by his own system.[2]

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[2]Ibid., p. 12234. The FERC rules do not use a collective term as we have for these services. Since we use the term "back-up" in a collective

Some Issues in Ratemaking for Back-Up Services

Assuming a cost based approach to ratemaking for back-up service raises social questions about whether or not any purposeful subsidy of back-up customers should be part of a back-up rate. Should, for example, those who use solar power, woodburning stoves, windmills, or other renewable resource systems to meet a significant portion of their energy needs be provided with some kind of incentive by utility companies to invest in and use these systems? The development of these systems in a utility's service area, after all, may reduce the utility's capital requirements for new plant construction. With the costs of utility long-term borrowing and construction set on what seems to be a continually upward path, reductions in a company's capital and building requirements can result in lower electricity costs for all consumers, and contribute substantially to improvement of the company's financial situation. The use of renewable resource systems in some service areas also may help to reduce the utility's consumption of oil, natural gas, and/or coal. The important national goal of conserving nonrenewable energy resources could thereby be served by the adoption of these systems, and the utility's unit energy costs could be lowered in the process as well. Some would argue that, to the extent these savings can be demonstrated, back-up customers should be given credit for them in their electric rate. One can legitimately question, however, whether it is wise ever to pay somebody for not consuming utility power. Otherwise, when is one to draw the line on granting such credits? Why should not homeowners who heat their homes with natural gas (and thus save the utility added capacity and fuel costs) be offered similar credits on the rate they pay for their electricity? Taking the issue to perhaps its absurd extreme, why should not the automobile manufacturer, who has considered locating an assembly plant in a utility's service area but later decided against it, receive regular checks from the utility for the capacity costs it saved as a result of his decision?

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sense, the term "stand-by" is substituted for what is called "back-up" in the FERC definitions.

Another question that has arisen in the consideration of back-up rates is whether or not back-up customers, especially small users, should be required to pay a minimum monthly or annual charge for a back-up subscription, even when they do not use any electricity. Such a requirement can arise because cost based ratemaking normally recognizes three types of utility costs: demand (or capacity), energy (running costs), and customer costs. Demand costs vary according to the customer's contribution to the utility's need to build plant capacity. Energy costs vary according to the customer's contribution to the utility's need to run these plants. However, customer costs, such as those for line-drop, metering, and billing, do not vary with consumption. They are incurred by the utility even though a customer may use no electricity. Therefore, a cost based rate for back-up service can require a perhaps substantial monthly charge to be paid by the customer even though he does not "use" the service. Some have asked whether the imposition of such a fixed charge in a back-up tariff does not effectively penalize those who have committed themselves to a worthy social goal--conserving our nation's energy resources. Does it not act in some kind of perverse way to discourage the very thing that every reasonable person agrees should be encouraged?

Except in the case of cogeneration rates, where federal rules have already required that rates reflect utilities' avoided costs, this report focuses on the development of methods for calculation of marginal costs of service and converting these costs into cost based rates. In general, we demur in making policy recommendations, especially those having to do with intentionally providing subsidies to one class of utility consumers (at the expense of another). In an economic sense, inter-consumer subsidies that affect prices always raise questions about their detrimental effects on economic efficiency. From a public policy viewpoint, intentional subsidies also raise political questions about who should receive subsidies, who should not, and who should be made to pay for them. Lastly, subsidies create questions about whether a particular subsidy is the most cost-effective strategy for addressing a particular problem. These are all difficult ratemaking policy questions, the correct answers to which only state public utility commissioners can provide.

The PURPA is far from unambiguous in providing guidance on these matters. It is on ratemaking questions such as these, in fact, that PURPA's three purposes for utility rate regulation (efficiency, equity, and conservation) tend to conflict most with one another. The U.S. DOE has stated its position on some of these issues, however, in the form of a voluntary guideline on the pricing of back-up service.

Department of Energy Voluntary Guideline

In February 1980, the U.S. Department of Energy issued its voluntary Guideline No. 2 pursuant to the Public Utility Regulatory Policies Act of 1978. The purpose of this guideline is to "assist state regulatory authorities and nonregulated utilities in their consideration of the ratemaking and other regulatory policy standards established under Title I of PURPA as they apply specifically to solar energy and renewable resource systems."[3] Although the guideline was issued to apply specifically to pricing back-up services for solar and other renewable energy resource installations, its provisions are general enough to apply to pricing back-up service for all types of customers. The provisions are outlined below and are offered as an indication of some of the difficulties involved in the determination of proper marginal cost-based rates for back-up service.

Within the guideline, DOE states that its position with regard to solar energy and renewable resource customers is that these customers should not be placed in a separate rate class, unless analysis indicates that their load characteristics are substantially different from the rest of the customer class of which they normally would be a part. Those different load characteristics must also have a concurrent impact on the cost of service to these customers. The DOE guideline further states that

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[3]Guideline No. 2 under the Public Utility Regulatory Policies Act of 1978: Solar Energy and Renewable Resources in Relation to the 11 PURPA Standards, U.S. Department of Energy, Economic Regulatory Administration, Office of Utility Systems, February 1980.

the creation of separate rate classes for solar and renewable resource customers may not be warranted in the near term given the paucity of back-up customer load data. However, where back-up load data are available in sufficient quality and quantity to demonstrate that costs of service are significantly different, separate classes for solar energy and renewable resource customers may be established.

In determining the costs of service for back-up power and the energy savings related to the introduction of solar energy and renewable resource systems, DOE recommends that the following factors be considered:[4]

1) timing of a utility's peak demand;
2) utility fuel mix as a function of load range;
3) local meteorological conditions with regard to their impact on solar energy and renewable resource system operation and the utility's load curve;
4) storage capacity of solar energy and renewable resource systems;
5) extent of solar energy and renewable resource end-use market penetration;
6) reliability of solar energy and renewable resource systems; and
7) characteristics of solar energy and renewable resource system load.

To justify the creation of a separate rate class or modification of an existing rate class for solar energy and renewable resource customers, DOE recommends that the following conditions be satisfied:[5]

1) the costs of serving the solar group differ substantially from those of the existing customer class;
2) there is no readily available method of reflecting these cost differences within the existing classes;
3) the solar energy and renewable resource group is discretely identifiable; and

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[4]Ibid.

[5]Ibid.

4) the costs of administration, including separate billing and special metering equipment, are not excessive.

Consistent with these criteria, a separate customer class may also be appropriate if solar energy and renewable resource systems possess special characteristics that offer unique opportunities to promote the utility's load management goals. According to the guideline, an evaluation of load management potential of solar energy and renewable resource systems should consider the following:[6]

1) the effect of back-up customers on utility load curves, i.e., the predictability of solar energy and renewable resource customer demand;
2) utility fuel mix by load type;
3) the costs associated with realizing the load management potential of these systems;
4) the interface with other load management techniques;
5) the level of penetration necessary to produce a beneficial impact;
6) utility system reliability; and
7) impacts on generating capacity deferral and distribution plant.

Lastly, the DOE voluntary guideline recommends that, to the maximum extent practicable, rates offered to customers in a special back-up service classification reflect marginal cost-of-service.

Experimental Rates by State Public Utility Commissions

A number of state public utility commissions have instituted solar energy rates for electric and gas utility customers. A National Regulatory Research Institute (NRRI) report,[7] based on information supplied by 51

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[6] Ibid.

[7] Richard J. Darwin, A Profile of Utility Rates Used for Solar Energy Applications, (Columbus, Ohio: The National Regulatory Research Institute, 1979).

public utility commissions, found that sixteen specific rates for solar energy users were in force in nine states for ten investor-owned utilities. Two of the solar energy tariffs were designed for use by natural gas customers, the rest for electric customers. The states identified as having solar energy rates are Illinois, Kansas, Michigan, New Hampshire, New York, North Carolina, South Carolina, Utah, and Wisconsin. In terms of rate design, some of the tariffs employ the traditional declining block approach, others use a flat rate, and one is based on time-of-use principles. All sixteen of the tariffs are experimental in nature and require the customer to agree to the use of special metering equipment to monitor loads and usage. Ten of the tariffs are for residential use only, and six tariffs include all customer classes. Several of the rates, as described in the report, are outlined below. They are presented for illustrative purposes to indicate how a state public utility commission and a utility might approach the problem of establishing rates for back-up service.

The Central Illinois Light Company instituted a residential solar-assisted electric space-heating rate on an experimental basis.[8] The rate offering was restricted to the first fifty customers who take service for domestic and general farm purposes. The overall rate included a one dollar customer charge and an energy charge based upon a declining block form, with a higher seasonal charge for all usage in excess of 400 kWh during the five months beginning in June. A condition for the rate is that customers must agree to permit the use of special equipment to measure load requirements and usage.

The Kansas Gas and Electric Company offered an "Experimental Off-Peak Storage Rider" for solar or mechanical-assisted space heating/cooling and water heating.[9] The tariff is limited to 200 customers whose total

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[8]Ibid., p. 9.

[9]Ibid., p. 15.

electric load is 400 kW or less. It is applicable to electric service for storage equipment used in the operation of heating, cooling, and water heating that is normally supplied from solar or mechanical sources. The off-peak period for purposes of this tariff is defined as 10 p.m. to 11 a.m., seven days a week. All provisions of the appropriate standard rate schedule apply except that a lower off-peak rate for the solar applications is offered.

The general terms and conditions for this tariff require that the customer bear all costs for the installation of a company-approved load control device and that the circuit supplying this load be separately metered. Any additional cost for metering devices or cabinets required to serve the off-peak load are to be paid for by the customer.

A final example of solar energy tariffs provided in the NRRI report is the two special contract tariffs of the Public Service Company of New Hampshire.[10] The first of these is between the utility company and Total Environmental Action, Inc. The service rendered under this agreement consists of the utility providing the customer off-peak electricity for controlled electric thermal storage for space heating in a solar-heated home. The tariff is part of an experimental load research program undertaken by the New Hampshire Public Utilities Commission. A rate of 1.95 cents per kWh for off-peak electric service was established as the average of uncontrolled space heating at 2.4 cents per kWh and controlled water heating at 1.5 cents per kWh. This off-peak rate is in effect from 10 p.m. to 7 a.m. for controlled, solar-assisted space heating. The rate was to be reduced to 1.9 cents per kWh if, after one year, the customer had not and did not intend to request an increase in the hours of operation. The difference (0.05 cents per kWh) for use up to that time is refunded to the customer. The rates charged to the customer for other uses are the same as in the standard tariff. The contract specifies that certain insulation

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[10] Ibid., p. 23.

standards be met and that the residence be heated by no other energy source. It also specifies that the utility company has the right to install, maintain, use, and remove timing devices, meters, and other types of measuring equipment.

The Public Service Company of New Hampshire also entered into a solar energy service agreement with an individual residential customer as part of an experimental load research program. The service rendered under this special contract consisted of furnishing off-peak electricity to be utilized for controlled back-up space heating in a solar-heated home by means of a customer-owned and installed thermal storage system. A rate of 1.9 cents per kWh was established for this service with the hours of operation limited to 10 p.m. to 7 a.m. There was no provision for the customer to request increasing the hours of operation. The rates charged for the customer's other uses were the same as set forth in the standard tariff, and the requirement for load monitoring and measuring devices was also specified.

A recent article appearing in Public Utilities Fortnightly[11] reports on a number of studies that have found that solar customers, with sufficient thermal storage and off-peak rates for charging this thermal storage, can eliminate any peak demands on the utility. They thereby cost no more to serve than other utility customers. The article cites a Congressional Office of Technology Assessment study that found that the cost, in cents per kilowatt-hour, of serving a solar home in Boston is thirteen percent less than that of serving a nonsolar home with a heat pump. The same study was reported to have found that the cost of back-up electricity (again in ¢/kWh) may be reduced as much as thirty-eight percent for solar homes in Boston when off-peak thermal energy storage systems are installed.

The article also reports that many public utility commissions have established rates which favor the use of solar energy or have policies

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[11]Donald R. Wallenstein, "Utility Company Interface with Alternate Energy Systems," Public Utilities Fortnightly, June 19, 1980, p. 29.

against back-up rates for solar customers higher than for standard service. Several utilities have offered solar customers the regular all-electric discount rate and have provided lower priced off-peak service for charging thermal storage. Finally, a number of states have passed statutes forbidding discrimination or increased rates to utility customers owning solar energy equipment.

With regard to multi-user solar or wind energy systems, the same article finds that substantial economies of scale can be derived from this type of renewable resource facility. These installations might be appropriate for apartment buildings, condominiums, shopping centers, industrial parks, mobile home parks, and district heating and cooling systems. There is, however, the question of whether or not these community solar and renewable resource installations might be subject to regulation as public utilities. A Utah case decision required that a shopping mall could not generate electricity for sale to businesses in the mall without commission regulation. On the other hand, states such as Minnesota have statutes which provide that there be no regulated utility status for a person who provides electricity only to the tenants in buildings owned by that person. Title II of PURPA gives the Federal Energy Regulatory Commission (FERC) the authority to exempt multi-user solar and renewable resource systems from regulation if they qualify as small power producers or cogenerators under Section 201 of the law.

CHAPTER 7

METHODS FOR COMPUTING THE MARGINAL COSTS OF AND RATES FOR BACK-UP SERVICES

As discussed in chapter 6, back-up service is a collective term referring to several different kinds of electric services that may be required by those using decentralized energy systems. Each of these services may pose different cost consequences for the electric utility. Some discussion of these services and their potential impacts on the utility, therefore, may be in order before presentation of costing and ratemaking methods.

Types of Back-Up Service Demand and Problems in Determining their Impacts on Utility Cost of Service

The three types of back-up service defined in chapter 6 are supplementary, stand-by, and maintenance power. These types vary in the predictability of their demands.

Types of Back-Up Service Demand

Supplementary power is supplied by a utility to a back-up customer on a regular basis to make up the difference between the customer's total need for power and what his facility can generate. Within broad parameters, at least, these demands are predictable for each customer class and type of self generation, much as the regular service load is predictable (subject to variation around stochastic factors such as weather). Such demands will require the utility to plan generating capacity much in the same manner as it plans to meet regular service demand.

Stand-by power is provided during forced outages of a customer's primary power source. For our purposes, we defined a forced outage condition as identifiable by the occurrence of mechanical failure in the customer's primary supply system. While an individual customer's need for this service is less predictable (in the short run) than is his need for supplementary power, the collective requirements for stand-by power by type of customer facility are predictable over the long run (in an actuarial sense). Therefore, after taking into account the coincident probabilities of customer forced outages occurring simultaneously, a utility will need to plan some amount of generating capacity to meet the stand-by power requirements of its back-up customers.

Maintenance power is provided during scheduled outages of a customer's primary power supply system. It is possible that maintenance activities requiring these scheduled outages generally can be performed during the utility's off-peak months or hours, so that the utility's idle generating plants can be employed to supply maintenance power to the back-up customer. Power provided at these times, therefore, places no upward pressure on utility capacity requirements. If, however, the customer's maintenance power requirements cannot be scheduled during the utility's off-peak times, then the demand takes on more of the cost characteristics of supplementary power and should be treated as such.

Problems in Determining Impacts on Utility Costs of Service

Historically, most utility back-up service customers have been large consumers of electricity, typically industrial cogenerators. Rates for this back-up service, much as has been the case for interruptible service, have been often negotiated by contract and based on some value-of-service principle. This industrial group may comprise the most significant candidate customer class for a cost-based interruptible tariff in many utility service areas. Another candidate class may be the relatively new collection of residential and non-residential small power producers. In most areas, however, they are still relatively few in number and small in total load. They own and operate primary generating facilities powered by solar, wind, or low-head hydro. Very little data appear to exist on the total costs of serving either of these two potential classes of back-up customers. In the first case, the paucity of cost information may be explained by the value-of-service, contract pricing tradition for industrial users. In the second, the lack of information on the back-up loads of small power producers is due to the utility industry's general lack of experience in serving such customers.

Only in one of the three types of back-up service--maintenance power--are the customer's load curve and cost of service fairly easy to predict in advance. As long as maintenance service is restricted to a utility's off-peak hours, its marginal cost will always be the marginal cost of providing power off-peak. The impacts of providing supplementary and stand-by power on the utility's cost of service are not nearly so clear. The stochastic factors affecting the demands for these services by customer class would appear to be substantial. Furthermore, the paucity of load data in many cases makes an unambiguous definition of cost-based customer class boundaries very difficult. The small number of such customers in most utility service areas often makes collection of these load data not worthwhile.[1]

In circumstances such as these, what approach can the state utility commission follow? Since the computation of the marginal cost of service for all types of back-up service will not be feasible in many cases, a commission may decide to adopt some form of experimental rate or just include back-up customers in regular rate classes until more is known about them. By simply dispensing with the task of calculating a cost-based rate and including back-up customers in current rate classes (until such time as a sufficient number of customers and quantity of load data are available to

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[1]The Solar Data Bank of the Solar Energy Research Institute, Golden, Colorado contains some information on solar energy supply characteristics. As can be expected, however, these data are limited in their applicability to specific geographic locations, site characteristics, and installation designs.

justify placing them in a separate class), the commission may effectively discourage the commercialization of some of these decentralized generating technologies. In doing so, it may forego the potential for any of their cost-saving advantages. In addition, setting rates for these services that are either too high or too low may lead to further distortion in the economic efficiency of the energy-producing sector of the economy. Furthermore, if these customers are placed in regular rate classes and back-up rates were to change dramatically in the future (as back-up customers' cost of service becomes known and they are placed in a separate rate class), future owners of these systems may find their installations suboptimal since their original design was based on earlier rates.

As with most new pricing policies and new load growth, the problem for the utilities and their regulators is what to do between the current period when there are few back-up customers on the utility system, and the future period when the number of these customers and their impact may be quite different. The experimental rate designs for solar energy customers presented in the previous chapter may shed some light on potential solutions to this problem. These experimental rates allow the utility to collect load data on back-up customers while still explicitly recognizing some of the possible load management advantages related to this type of load growth. Although the costs of doing so can be a problem, utilities may be able to obtain a fair estimate of these potential advantages by analyzing the extant data on small power producers' load characteristics and by discussing the likely impacts with manufacturers and distributors of the systems. Although costs are again a factor to be considered, limiting the hours of electric service provided to these customers can ensure that they will not place an undue cost burden on the utility and its regular customers. Experimental programs may permit the utility to take advantage of any load management economies that might exist, to limit the negative impacts any of these customers may impose, and at the same time to include them in the company's regular load research program as they become sufficiently numerous.

Fortunately, this lack of information on load characteristics may not be so serious a problem with many high-volume, industrial or commercial customers. Some already have long utility service records and may have established their load characteristics under contract. Special metering and control devices and time-of-use rates also may be more cost-effective in the service of this class.

In the following section, we discuss how to compute the marginal costs of back-up services when circumstances permit and suggest marginal cost based solutions to the ratemaking problem when circumstances do not.

Methods for Computing the Marginal Costs of and Marginal Cost Based Rates for Back-Up Services

This discussion proceeds by considering the types of back-up service one at a time: maintenance power, supplementary power, and stand-by power.

Maintenance Power

Of the three types of service, maintenance power has the most predictable load pattern and thus the most predictable set of cost consequences for the utility providing it. Its costs can be more easily predicted because its use can be scheduled. The timing, maximum demand in kilowatts, and hours of maintenance power load duration all can be at least approximately determined in advance.

As long as the consumer's planned outages are scheduled during the utility's off-peak periods, when idle generating capacity is available, the consumption of maintenance power should exert no upward pressure on the utility's total capacity requirements.[2] As a consequence, the marginal

[2]Of course, this may not be true if the customer's demand for maintenance power, whenever it may be scheduled, exceeds the utility's available idle generating capacity. This situation could occur, for example, if a large industrial cogenerator were to locate in the service area of a small utility. Under the FERC's PURPA Section 210 rules

costs of capacity for this service may be taken as zero. The marginal cost of energy for supplying maintenance power under these conditions is the utility's incremental running costs for the off-peak periods when the service is supplied. This cost can be computed using the same general formula as was suggested for calculating a utility's decremental energy costs for cogeneration purchases (see equations 3.1, 3.2, and associated text). The only special care that must be taken is in selection of the correct hours over which lambdas will be averaged or the power cost simulation will be run. The customer costs for this service are the same as for other customers in the same customer class except for the cost of special metering or load control equipment. It may also be reasonable to reduce customer charges by an amount that reflects the savings due to a less frequent need for meter reading and billing by the company.

If not all of the customer's demand for maintenance power can be restricted to times when the utility has idle capacity available to meet it, then the demand should be costed and rated as though it were supplementary power service.

Supplementary Power

A customer's pattern of consumption of supplementary power depends on the relationship between his total need for power and the output of his primary system. In order to determine the cost consequences of this difference for the utility, the customer's deficiency must be measured over some period meaningful in terms of the utility's daily and seasonal load cycles, e.g., one year. If time-of-day rates and time-of-day metering are available and are cost-effective for the customer, then the cost-of-service consequences of varying consumption patterns for supplementary power can be

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(§292.305, paragraph b.2.), such utilities may be waived from the requirement to provide service. The costs of providing maintenance, supplementary, and stand-by power under these circumstances will not be analyzed here.

automatically accounted for in the time-of-day billing system. For large volume users, time-of-day metering may be cost-effective (or already in place) and thus time-of-day rates may be an option for commissions to consider for pricing supplementary power sales to these customers. The time-of-day rate charged for supplementary power in these cases would be the same as that charged for regular service customers of the same customer class, except for the possibility of a reduced customer charge when the need for less frequent meter reading is indicated.

In many situations, however, time-of-day rates may not be feasible, especially for low-volume residential customers. In these situations, information on the supplementary power users' load curves by time of day, day of week, and season of the year is needed to determine the marginal cost of providing service. Were it available, this information would probably reveal substantial differences in the power demands of back-up customers. In the residential class, for example, a customer with passive solar space heating and thermal storage capability, with electric space heating as a supplement, is likely to have a far different pattern of demand for supplementary power than a customer who uses a windmill with battery storage for his non-heating power needs, and who relies on the utility connection as a supplement when the wind does not blow. An industrial customer who needs supplementary power from the utility only during his peak production period is likely to have a pattern of demand quite different from either of these first two. In addition, the cost impacts of each of these varying customer load patterns may differ according to the peaking pattern of the utility (e.g., summer versus winter).

While this type of information on customer loads is needed to estimate the marginal cost of service for supplementary power, it is also expensive to collect. Practically speaking, collecting load data is worthwhile only when the annual power sales to the customer class are large enough to justify the expense of the load research. For example, load data are required under PURPA Section 133 Cost-of-Service Information filings only when the customer class constitutes ten percent of system demand or five percent of total kilowatt-hour sales.

When these load data are available, customer class loads could be forecasted over the utility's capacity planning horizon and the marginal costs of generation (capacity and energy) could be calculated by methods similar to those used for cogeneration and interruptible service customers: a system expansion planning model could be run twice, once with and once without these customers on the system; the difference in the cost per kilowatt of the utility's future capacity requirements, expressed in current dollars, could be taken as a measure of the marginal cost of generating capacity for serving these customers; and the system's short-run incremental operating costs per kilowatt-hour during the period when service is required is the marginal cost of energy associated with providing their service.

When these load data are not available, a commission's most prudent course may be to assume that the marginal cost of serving supplementary power customers is no different than that of the regular service rate class to which they would otherwise belong. This means including them in an appropriate residential, commercial, or industrial rate classification until such time as evidence indicates that separate rating classes should be established for them.

Stand-By Power

Calculating the marginal costs of generation capacity required to provide stand-by power also requires data that may be difficult to obtain and a probabalistic analysis that may be complicated to perform. For example, in order to know the amount of utility generating capacity that must be built and set aside for stand-by service, one would have to know:

1) the expected number of kilowatts of demand and number of hours duration of each stand-by customer's power requirements during a forced outage of his facility;

2) the expected frequency of forced outages for each customer; and

3) a set of hourly probabilities that express what is known about the expected timing of these outages, so that the likelihoods of various levels of stand-by load coming on line at different hours can be compared to the utility's expected regular loads and available generating capacity during these hours.

With this information, the utility could plan enough additional generating capacity to meet stand-by demand at a loss-of-load probability equal to that used to plan for total system load. The cost per kilowatt (in present dollars) of this incremental generating capacity can be taken as the marginal cost of generating capacity for stand-by service. If one had all of this information, one could also determine the utility's incremental system running costs in cents per kilowatt-hour of providing stand-by service.

Practically speaking, however, the availability of these data and justification for doing such an expensive cost analysis may be as lacking for stand-by service as they were for supplementary service. This is especially true in the case of small-volume users. From a cost-of-service perspective, the only aspect of stand-by service that can be fairly well predicted in advance is that the customer costs associated with it are going to be approximately the same by customer class as they are for regular service. As we have already mentioned for the other types of back-up services, these costs may be reduced somewhat by the less frequent need for meter reading and billing. By definition, customer costs are generally unrelated to the amount of power consumed. Therefore, a cost based rate for stand-by and other types of back-up customers would include a standing monthly charge to cover the utility's customer-related costs, regardless of the amount of power consumed during each month.

Without knowledge of the factors that affect the utility's variable costs of serving these customers, a commission's only short-range ratemaking alternative may be to permit the utility to charge a regular service rate (by customer class) for power consumed by stand-by customers. As the utility's experience with and total sales to these customers increase, studies to determine the costs of serving them may become cost-effective. Only then will a separate, cost based stand-by rate become feasible.

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