ELECTRIC RATE REFORM AND ALTERNATIVE ENERGY SYSTEMS

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ABSTRACT

State regulatory commission hearings on purchase and buy back rates for electric utility customers with dispersed power systems that utilize alternative energy sources are currently underway. In this article the author discusses the economic principles for efficient rates to these customers and concludes that a variety of rate incentives can be used to achieve the PURPA objectives of conservation and efficiency in the utilization of utility resources.

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Persistent increases in international energy prices and growing concern over the availability of conventional energy supplies has fostered much discussion about the possible role of alternative energy sources such as solar, wind, tidal and biomass in America's energy future. Since the OPEC oil embargo a flood of special studies by prestigious experts has produced a variety of feasible energy scenarios.[1] One clear point of agreement is that alternative energy sources will make an increasingly important contribution to the nation's energy supply. The influential Harvard Business School study[2] suggested that as much as 20 percent of U.S. energy requirements could be produced from alternative energy sources by the turn of the century.

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[1] Some of the more well known studies are: A Time to Choose, Energy Policy Project of the Ford Foundation, Cambridge, Mass: Ballinger, 1974; Energy: The Next Twenty Years, A Report sponsored by the Ford Foundation and administered by Resources for the Future, Hans Landsberg (Study Group Chairman), Cambridge, Mass: Ballinger, 1979; Energy in America's Future: The Choices before Us, a study by the Staff of the Resources for the Future National Energy Strategies Project, Sam Schurr (Project Director), Baltimore: John Hopkins University Press, 1979.

[2] Energy Future: Report of the Energy Project at the Harvard Business School, edited by Robert Stobaugh and Daniel Yergin, New York: Random House, 1979.

One important proviso of these studies is that economic and institutional barriers to alternative energy uses (e.g. solar access, zoning, lending practices, etc.) must be reduced before these sources will be used efficiently in the energy system. Many state and local governments have enacted legislation to encourage alternative energy sources through special zoning, tax exemptions and loan programs.[3] At the Federal level, the National Energy Act (NEA) of 1978 provided grant funds for alternative energy systems plus income tax credits and deductions for industrial and residential uses of alternative sources.

The most significant aspect of the NEA for alternative energy systems was the requirement in Titles I and II of the Public Utilities Regulatory Policies Act (PURPA) that state utility commissions consider and, in some cases, implement new rate structures for dispersed energy systems[4] that use alternative sources. In accordance with this legislative directive, the Federal Energy Regulatory Commission has promulgated mandatory rate reforms for small power producers and cogenerators[5] while the Economic Regulatory Administration has outlined voluntary ratemaking guidelines for solar and renewable resource users

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[3]A summary of recent legislation is provided in "A Survey of State Approaches to Solar Energy Incentives", Solar Energy Research Institute, TR-62-265, December, 1979.

[4]The term "dispersed system" is used generically to denote all energy systems that produce power at the customer's site. This includes alternative energy sources as well as conventional non-liquid fuels. Cogenerators are also included.

[5]"Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978", Federal Energy Regulatory Commission, Federal Register, Vol. 45, No. 38, Feb. 25, 1980.

that do not sell surplus electric power.[6]

The pros and cons of several provisions of PURPA have been debated extensively in this journal, but relatively little discussion has occurred about ratemaking for customers using alternative energy systems. Since many alternative energy sources are intermittent, customers using dispersed systems must rely on the electric utility to provide power during slack production periods or to purchase electric power from the customer's system when production exceeds the customer's needs. Depending on the type of rate incentives provided by the utility, these potential changes in utility load can either benefit the utility through improved load factor and deferred construction or they can cause sharper peak loads and financial difficulties. Numerous rate structures for dispersed systems have been proposed and implemented in recent years.[7] In this article, I outline a general framework for determining whether these rate structures will promote economically efficient uses of dispersed systems and whether they are consistent with the FERC regulations and ERA guidelines. The purpose is not to advocate particular definitions or methodologies but to explore the

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[6]"Voluntary Guidelines for Solar Energy and Renewable Resources Respecting the Federal Standards Under the Public Utility Regulatory Policies Act of 1978", Economic Regulatory Commission, Federal Register, Vol. 45, No. 37, February 22, 1980.

[7]A summary of these different approaches is provided in "Utility Company Interface with Alternate Energy Systems" by Arnold R. Wallenstein, Public Utilities Fortnightly, June 19, 1980.

economic implications of different rate structures for dispersed system customers. In this fashion, it can be shown that many different rate structures can promote the efficient use of alternative energy systems.

In the first section a brief overview of the FERC regulations and ERA guidelines is presented. Next, I present a graphical analysis of the economic factors influencing rate design for dispersed systems and evaluate the impact of different rate structures for both stable and expanding electric systems. I then turn to a discussion on the use of dispersed systems in load management programs and conclude with a word about the role of rate reform for alternative energy systems in promoting PURPA's objectives.

FERC Regulations and ERA Guidelines

The FERC regulations require state regulatory authorities and non-regulated electric utilities to implement specific ratemaking standards no later than March 20, 1981. The standards apply to qualifying co-generation facilities (defined as equipment used to produce electric energy and useful thermal energy from conventional and/or alternative energy sources) and small power producers (defined as facilities that produce no more than 80MW of electric power using biomass, waste, and renewable resources as a primary energy source and which a utility controls less than 50 percent of the equity interest).[8] The rate-making standards require that electric utilities with total sales (other than resale) of more than one billion kilowatthours after December 31, 1975, shall:

[8]This is only a brief sketch of the qualifying requirements. For more detail see "Small Power Production and Cogeneration Facilities - Qualifying Status" Federal Energy Regulatory Commission, Federal Register, Vol. 45, No. 56, March 20, 1980.

1) provide data on the present and future costs of energy and capacity on their system (§292.302);

2) purchase electric power from qualifying cogenerators and small power producers at rates reflecting the "avoided cost" to the utility of producing an equivalent amount of electric energy (with adjustments for reliability) (§292.304); and,

3) Provide electric power to cogenerators and small power producers at rates based on consistent systemwide costing principles that are not discriminatory (§292.305).

Although the exact terminology is not used, the standards indicate that marginal costing principles should be the basis for purchase and sale agreements. Unlike the eleven voluntary ratemaking standards specified in Title I of PURPA (which Paul Joskow says "have a decidedly marginalist flavor to them"), these standards must be incorporated with the ratemaking process. However, ". . . the Commission believes that the selection of a (cost) methodology is best left to the State regulatory authorities and nonregulated electric utilities charged with the implementation of these provisions"[9] and, the states do have "flexibility for experimentation and accomodation of special circumstances"[10].

The ERA guidelines apply the eleven ratemaking standards in Title I of PURPA to non-generating users of alternative energy technologies. In essence ERA advocates ". . . the use of marginal cost pricing as a means of designing rates which are nondiscriminatory not only to solar energy and renewable resource customers but also to all other

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[9] FERC, op. cit. at 5, p. 12226.

[10] Ibid.

customers."[11] And, these customers should "not be considered for separate classification unless the load curves and costs-of service imposed by such customers can be determined to be significantly different from the load curves and cost-to-serve of the customers in the existing rate class."[12] Furthermore, the ". . . electric utility should be required to provide information to customers about the implications of its rate structure for the use of solar energy and renewable resource systems."[13]

THE ECONOMICS OF DISPERSED POWER SYSTEMS

Dispersed power systems can make an efficient contribution to community energy needs if these systems supply power to the end user at a lower cost than the electric utility. This simple assertion does not imply that dispersed systems must produce at lower cost for all levels of output at all times. Because most alternative energy sources are intermittent and an utility's cost of generating electricity vary by time-of-day and season, economic feasibility depends on whether the cost of dispersed power is less than the utility's cost during specific periods of customer demand. This highlights an important interdependence: customer demands could be met from dispersed production and/or utility production; the customer should be given a price signal to select the lowest cost alternative. The implication of this interdependence for rate structure design can be

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[11] ERA, op. cit. at 6, p. 12190.

[12] Ibid, p. 12199.

[13] Ibid, p. 12200.

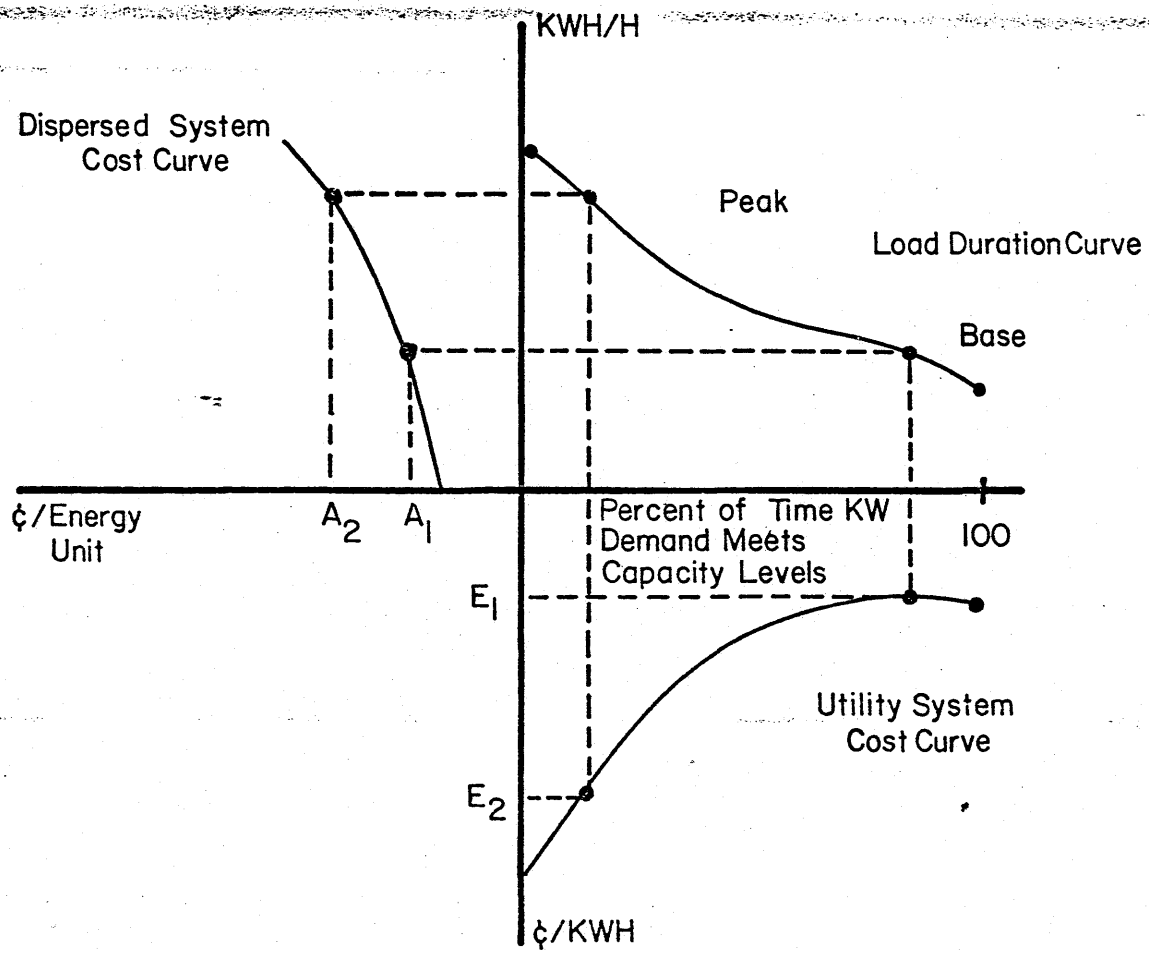
elaborated by considering examples of a stable utility and a growing utility.

The Stable, No-Growth Case

Consider the situation for a utility system that has a stable load and sufficient generating capacity to meet load and margin requirements for the planning horizon. In this situation rates for purchases from the utility should encourage dispersed technologies that can produce during any portion of the load cycle at lower cost than the utility's marginal cost of production. As long as the portion of load supplied by dispersed systems does not significantly change the load curve, the net result is a substitution of alternative energy sources for higher cost utility output. This situation is displayed graphically in Figure 1.

The upper right hand panel is the familiar load duration curve for electricity during a particular period (day, season, etc.). Power demand is measured (in kilowatthours per hour) on the Y-axis and the percent of time during the period that a certain level of demand occurs is measured on the X-axis. The lower right hand panel relates the marginal cost of a utility to the power demands given by the load duration curve. Marginal cost per unit (in cents per KWH) is graphed along the Y-axis. We assume that the utility employs the least cost combination of generating units. The slope of the curve reflects the well-known principle of utility system dispatch that incremental units of generating capacity are used in order of cost to meet demands

Figure 1: Relationship Between Electric Power Load Curve and Marginal Cost Curves for Utility Power and Dispersed Power



of different rate and duration.[14] Due to exhaustion of scale economies, we would expect the marginal cost to level off regardless of the utilization.

The upper left hand panel is a marginal cost curve for a particular dispersed technology in the utility's service area. The cost per unit of energy (expressed in cents per BTU) is graphed along the X-axis and is directly related to the load profile of the utility. For this dispersed technology, production during peak loads is more costly than during base loads. Other dispersed technologies may have different cost curves (e.g. lower costs during peak than during base); the actual cost curves in a specific service area will be determined by the type of dispersed technology, the availability of alternative energy sources, and the load profile for the service area. To simplify the discussion, the single cost curve in Figure 1 can convey the main points of this analysis.

Consider the incentives created by a rate strucutre for purchases from the utility based on marginal costs. In Figure 1, a customer could purchase from the utility during base load at a price of E_1 or produce the energy directly from a dispersed system for cost A_1. Similarly, for the peak period, the cost comparison is E_2 and A_2. For

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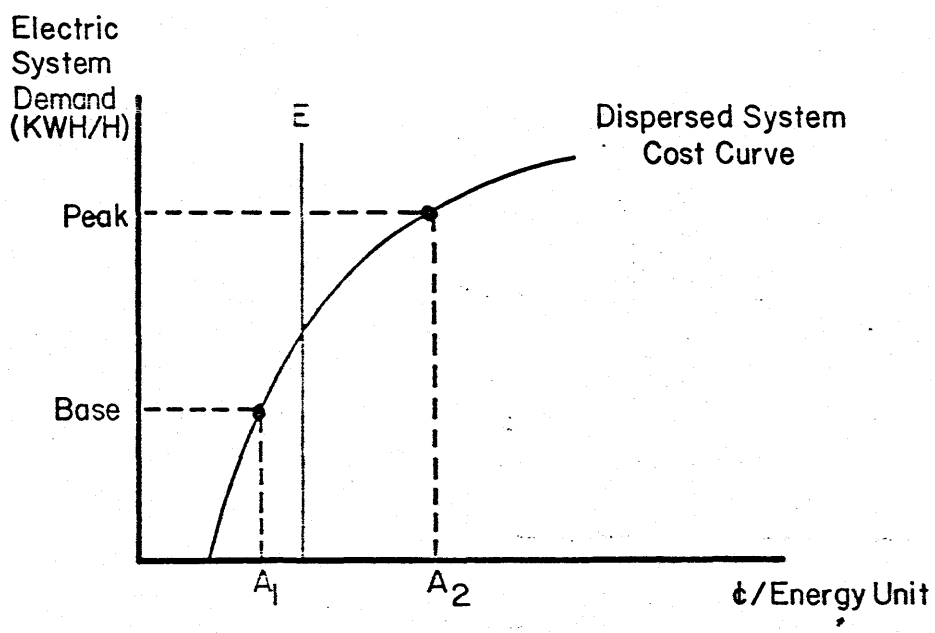
[14] Only generating costs are considered in this discussion because it is unlikely that transmission and distribution costs will change significantly and these costs are a relatively small portion of total costs.

example, if $E_2 > A_2$ and $E_1 < A_1$ the customer would use the dispersed system during peak and purchase during base. In this situation the customer's total cost for energy is reduced and the utility realizes a saving in peak fuel consumption.

A comparable result would occur for sales to the utility from the customer under a marginal cost based rate structure. If A_2 is less than the utility's "avoided cost" of E_2, the customer would sell energy to the utility during peak and purchase during base. In this example, the only avoided costs for the utility would be fuel savings during peak since no capacity reduction would occur. The net result is a substitution of alternative energy sources for conventional fuels.

The inefficiencies that could result from backup and buy back rates based on average, embedded costs instead of marginal costs are illustrated in Figure 2. This is a turned around version of the dispersed technology cost curve from Figure 1. If the backup rates to the dispersed customer is the average cost based rate of $\bar{E}$ regardless of the time the customer demands energy, then the customer would utilize the dispersed system only during the base period when the dispersed system costs are lower than the backup rate and purchase energy from the utility during peak. The customer has no incentive to consider the true cost of producing backup electricity. As a result, even though the customer is minimizing his own cost, this is inefficient because a more costly substitute is being used during base load while the lower cost dispersed system is left idle during peak load. If the buy back rate is based on the average cost as a measure of the avoided costs, then the utility's total costs would

Figure 2: An Example of an Average Cost Rate for Utility Power Compared to the Marginal Cost of Dispersed Power at Different Times During System Load.



increase since it would have to purchase more costly energy from dispersed systems during base load.

Efficient pricing incentives that convey information about the comparative costs of utility and dispersed system production are readily transmitted through a time-of-use rate structure. The FERC requirements for purchases from cogenerators and small power producers at a utility's avoided cost and backup rates based on non-discriminating costing principles indicate that time-of-use pricing will convey incentives to promote the efficient use of dispersed energy systems.[15] It is clear that utilities will need to track marginal costs to meet these requirements. Extending the time-of-use backup rates to include non-generating dispersed system customers would encourage an efficient integration of all dispersed systems with the utility.

State commissions may decide, however, that metering and other administrative costs for time-of-use rates to non-generating dispersed system customers outweigh the benefits. In this case, even if the general rate structure is based on a utility's average cost, efficient pricing incentives can be achieved by special credits or surcharges. For example, a utility could offer a special fuel charge

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[15] From a utility's perspective, buy back rates may still be a problem. Unless a utility is allowed to pass on the cost of purchased power to other ratepayers, a utility has little incentive to buy from dispersed system customers.

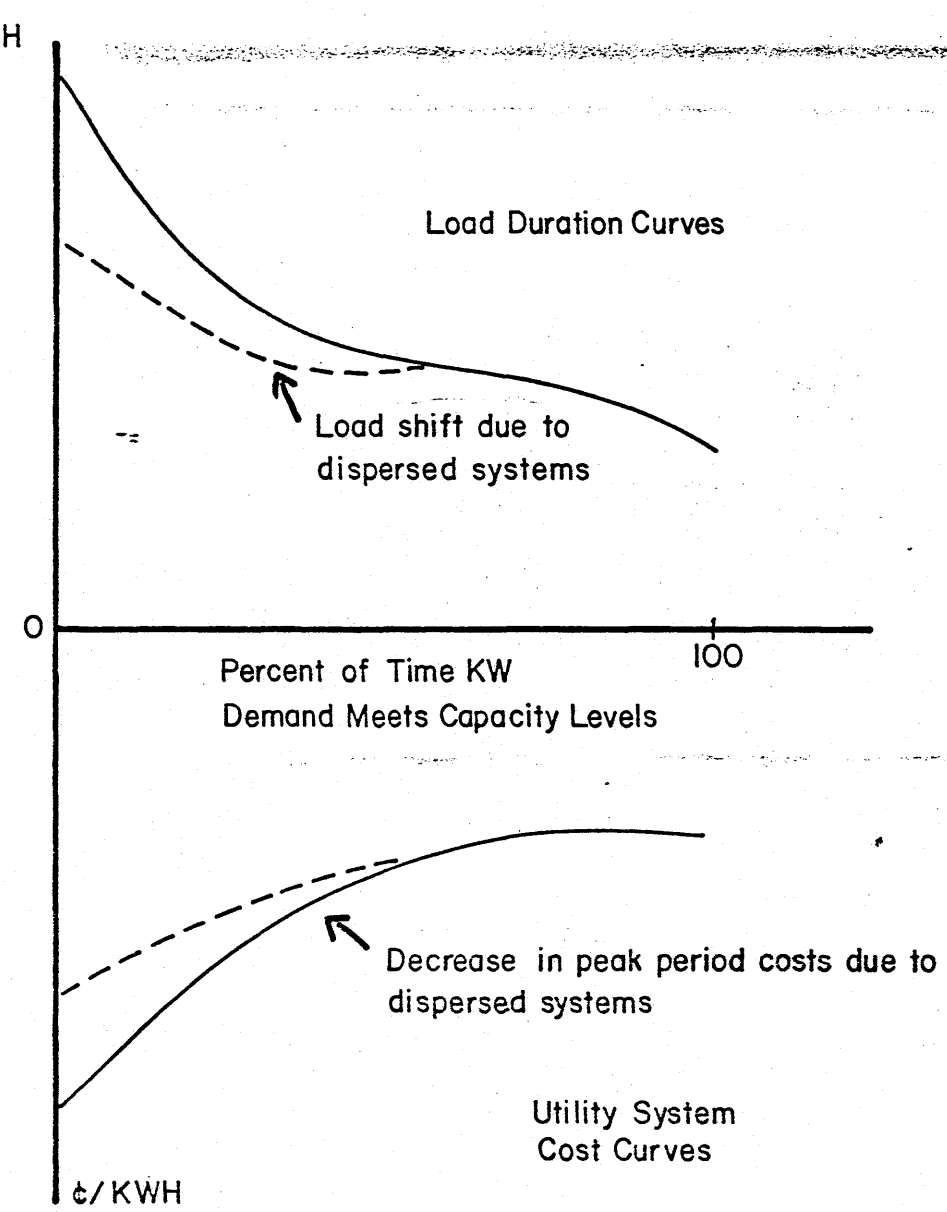
credit for dispersed technologies that do not require backup during peaks. This encourages off peak purchases from the utility and reduces peak fuel use. The critical factor in determining whether a credit or surcharge is appropriate can only be determined by analyzing the production capabilities of a dispersed technology in relation to each utility's load and cost characteristics. This analysis becomes more complicated when we consider a growing utility system.

The Growth Case

The impact of dispersed systems on electric power systems is most significant when we consider the long run effect on load and generating capacity. For certain systems that plan to change generating capacity (either to meet load growth or to switch fuel sources), the benefits of well designed rate incentives for dispersed systems can be fuel savings and reduced capital requirements. A poorly designed rate structure may actually lead to increased capital requirements and higher costs for all system customers.

Assume once again that the purchase and buy back rates for dispersed system customers are based on marginal costs during various periods of use and that some dispersed systems can produce power at lower cost than the utility during peak periods. As illustrated in Figure 3, a result is the substitution of dispersed production that reduces the peak demand on the utility. Depending on the magnitude of the peak reduction, the utility can defer or cancel peak capacity additions that would otherwise be required or increase utilization of more energy efficient generating units. The net result is a downward shift of the utility's marginal cost curve that results in lower costs for all customers during peak periods.

Figure 3: An Example of the Long Run Impact of Marginal Cost Pricing for Dispersed System Customers on Utility Load and Costs.



On the other hand, a scenario could exist where dispersed production causes reduced base load and poor load factors. If purchase and buy back rates are based on marginal costs, this would imply that dispersed systems can produce power at lower cost than utility base load units. However, as Asbury and Webb[16] have argued, this is an unlikely event.

A rate structure for dispersed system customers that does not provide incentives to utilize dispersed production efficiently can have negative long run impacts on the utility. Consider the situation described earlier in Figure 2 where an average cost based rate is used for purchase and buy back agreements regardless of the time of use. Dispersed system customers that could produce during base periods at lower cost than the utility's average cost would supply their own power or seek to sell to the utility during this period while purchasing all of their power from the utility during peak periods. The result, illustrated in Figure 4, is an erosion of the utility's base load and decreased utilization of the more efficient base generating units leading to higher marginal costs during the base period and higher average costs. Even with load growth, the reduced load factor forces the utility to meet new growth with less efficient peaking units. In order to meet revenue requirements, the utility would have to increase rates for all customers.

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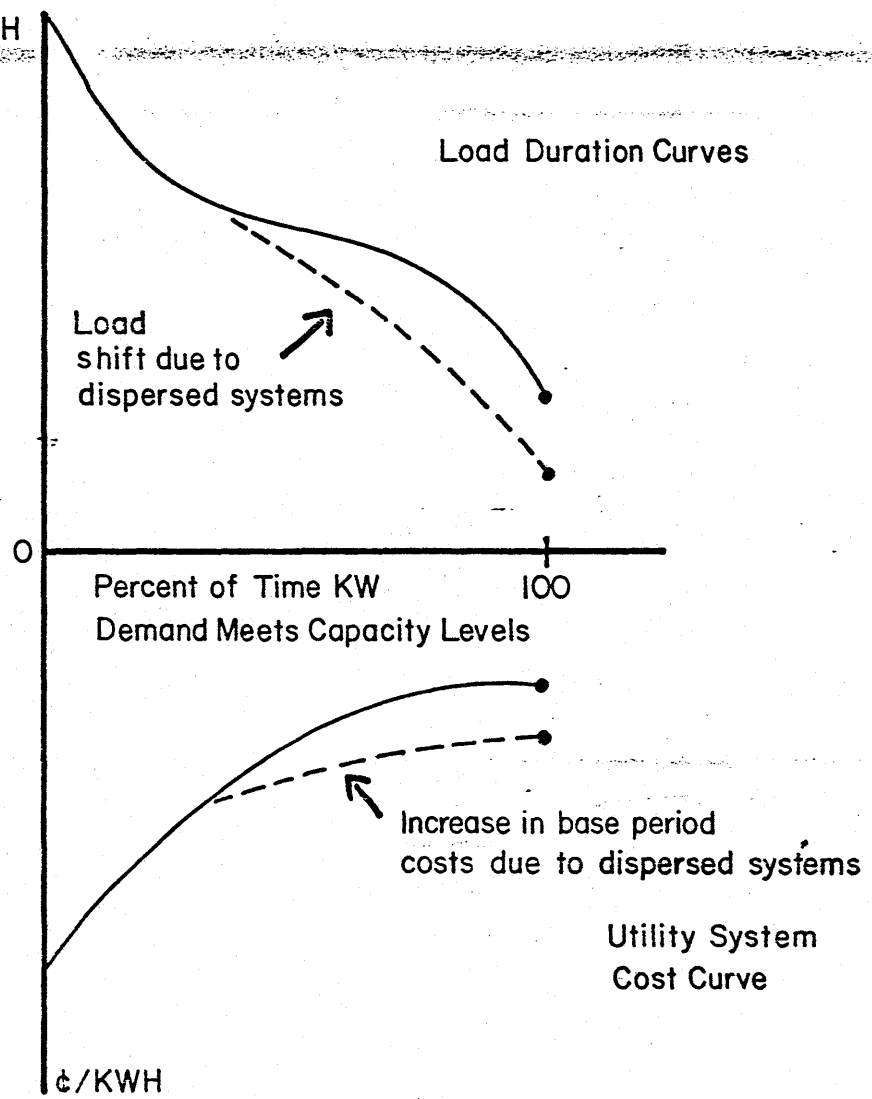
[16] "Decentralized Electric Power Generation: Some Probable Effects" by Joseph G. Asbury and Steven B. Webb, Public Utilities Fortnightly, September 25, 1980.

[17] This outcome is indicated in H.G. Lorsch's study of the affect of solar space conditioning on Philadelphia area utilities; see "Implication of Residential Solar Space Conditioning on Electric Utilities", Franklin Institute, Philadelphia, Pa., December, 1976.

Figure 4: An Example of the Long Run Impact of Average Cost Pricing on Utility Load and Costs.



Of course, the actual changes in a utility's long run marginal cost due to load displacement by dispersed systems will depend on a number of factors. The age and composition of existing generating capacity will affect the choice of future capacity additions and the pattern of load displacement by dispersed systems will determine whether peaking or base capacity will be needed to meet load growth. Similarly, utility planners must consider the overall impact on system load of other rate reforms such as time of use pricing.[18] The interaction of these factors will determine the direction of change in the long run marginal costs for each utility.[19]

In addition, an important issue is the consideration of reliability in purchase and sale agreements between a utility and dispersed system customers. The output from dispersed systems will vary with capacity, technological type, and power requirements of the user. Utility rate structures for sales to dispersed system customers that do not consider these reliability characteristics will encourage customers to shift the risk of supply to the utility and to under-invest in reliability features in system design (i.e. capacity, storage, etc.) As a result the utility's demand volatility may increase, especially in service areas where dispersed systems rely on natural forces such as solar and wind power that are determinants of utility demand. The likely result would be added investment in utility reserve capacity and higher costs for all utility customers.

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[18] "Do Time-of-Use Rate Change Load Curves? And How Would You Know?" by J.P. Acton and B.M. Mitchell, Public Utilities Fortnightly 105, May 22, 1980, pp. 15-24

[19] The implications of movement along the utility's long run marginal cost curve are explained in greater detail in "Long Run Marginal Costs Lower than Average Costs" by S.R. Hunter, Public Utilities Fortnightly 105, January 3, 1980, pp. 17-19.

The arguments for including reliability factors in purchase agreements from cogenerators or small power producers are similar. Different dispersed technologies will provide power to the grid at different times. Those systems with a higher probability of availability are more likely to realize the estimated "avoided costs" of the utility. If rates for purchase do not reflect these differences in reliability, customers will not have an incentive to use technologies that maintain the quality of supply from the electric grid and improve the efficiency of power supply. The FERC rules permit rates for purchase to"differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies." (§292.304(c)(3)(ii)).

There is no single type of rate structure that will permit all of these factors to be considered. Once again a time-of-use framework would convey efficient pricing signals but special consideration would still be required to determine purchase and buy back rates for dispersed customers with different levels of reliability. The most important advantage of the time-of-use rate in the case of a growing utility is that it would include a cost component that reflects the utility's avoided cost of capacity.[20] This would convey information to potential dispersed system users about the types of technologies

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[20] Whether marginal generating capacity costs are based on peak or base load costs is an important issue that will affect the calculation of the utility's avoided cost. For a discussion of these issues, see "Marginal Cost: How Do Methods Compare" by J. Schaefer, Electrical World 189, February 15, 1979, pp. 84-86.

that would lead to long run benefits for the customer and the utility.

These desirable pricing incentives could also be captured with special credits or surcharges to the general rate structure. The main difference here for the case of the growing utility is that the credit or surcharge should include both capacity and energy components to reflect the impact of different dispersed technologies on utility costs. For example, wind systems in a particular service area could be assessed a surcharge if power is demanded from the utility during the peak and a credit that reflects the marginal cost of peak capacity could be given for power sold to the utility during the peak. Many variations are possible but the key concern should be that the surcharges and credits are based on realistic capacity cost increases or savings.

CONCLUSIONS

Alternative energy systems can make an important contribution toward the PURPA objectives of conservation of electric energy and increased efficiency in the utilization of utility resources. Efficient rate structures based on avoided (marginal) costs will encourage economically viable dispersed systems to offset the utility's most costly output. In conjunction with a time-of-use pricing program, integration of dispersed systems with the utility electric grid could increase utilitzation of base load generating units and shift fuel consumption from oil and natural gas to coal and nuclear power. At the national level this could produce significant petroleum conservation benefits. For example, Whipple estimates that by the year 2000 solar heating alone could shift 1 or 2 quads per year from premium

fuels to domestic supplies of coal and uranium.[21]

Integration of dispersed systems could also provide load management benefits for the utility. Instead of investing in 'finger in the dike' remedies such as radio controlled interruptible loads, utilities could encourage customers to adopt dispersed systems that offer long run capacity and energy savings. This strategy would mitigate customer dissatisfaction about load interruptions and the consequent loss of consumer surplus resulting from these efforts. Furthermore, from the utility perspective, active promotion of dispersed systems is a cost effective strategy[22] since the costs of obtaining increased efficiency in the utilization of utility capacity are shifted directly to the customer and the Federal government through the income and investment tax credits for alternative energy systems provided in the Energy Tax Act of 1978 and the Windfall Profits Tax of 1980.

Considerable research on the potential role of dispersed systems in electric power systems is still needed and preliminary results are not promising. For example, Asbury et al. found little difference

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[21] "The Energy Impacts of Solar Heating" by C. Whipple, Science 208, April 18, 1980, pp. 262-266.

[22] Under Section 115 of PURPA load management techniques are cost effective if they are likely to reduce peak demand and the long run cost savings to the utility exceed the long run costs of each technique. This is a weaker test than that required for time-of-use rates in which the long run benefits must exceed the costs to both the utility and it's customers.

between the demands of conventional and solar heating customers for utility supplied electricity during peaking periods in seven of eight U.S. cities studied.[23] Similarly, Bae and Devine observed low correlation between wind power availability and peak electric demands in Norman, Oklahoma.[24] These early results, however, cannot be taken as general conclusions about these dispersed systems or the potential role of alternative energy systems. Each dispersed technology and utility system is different; only a careful analysis of the impact of particular technologies on the present and proposed generating system will determine whether alternative energy systems are advantageous.[25]

The magnitude of the contribution alternative energy systems can make to U.S. energy needs depends on international events, technological advances, and numerous economic developments. Careful consideration of electric power rate structures for dispersed systems will increase our understanding of the complementary relationship between utilities and dispersed power system. In the long run,

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[23] "Solar Availability for Winter Space Heating: An Analysis of SOLMET Data, 1953 to 1975" by J.G. Asbury, C. Maslowski, and R.O. Mueller, Science 206, November 9, 1979, pp. 679-681.

[24] "Optimization Models for the Economic Design of Wind Power Systems" by H.M. Bae and M.D. Devine, Solar Energy 20, 1978, pp. 469-481.

[25] For an analytical model that incorporates the key points in this article, see "An Economic and Energetic Framework for Evaluating Dispersed Energy Technologies" by J.W. Milon, Land Economics 57, February, 1981.

rates that reflect the true cost of power from a variety of energy systems at different periods of time will benefit both utility customers and society.