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A METHOD FOR COMPUTING MARGINAL COSTS
ASSOCIATED WITH ON-SITE ENERGY TECHNOLOGIES

R. Bright and H. Davitian

August 1980

NATIONAL CENTER FOR ANALYSIS OF ENERGY SYSTEMS
DEPARTMENT OF ENERGY AND ENVIRONMENT

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ECONOMIC AND SYSTEMS ANALYSIS DIVISION

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PREFACE

Since 1978, the National Center for Analysis of Energy Systems has had a program of studies investigating the potential impacts that decentralized, utility-interconnected energy production technologies might have on electric utilities. The emphasis in these studies is on the long-run costs imposed on utilities when they provide supplementary power to these devices and the long-run savings they experience when power is delivered to the grid by the devices. The technologies include cogeneration, solar heating and hot water systems (with electric backup); photovoltaic systems, wind, etc.

Initial funding for these studies was provided by the Market Analysis and Evaluation Branch of the U.S. Department of Energy under Dr. Roger Bezdek. This funding supported the development of a method of long-run marginal cost and marginal fuel-use analysis and its application to residential solar heating and hot water systems. Subsequent funding from the Systems Analysis Branch of the Economic Regulatory Administration and Sandia Laboratory has supported the refinement of the method and its applicability to additional technologies.

This report is a detailed description of the analytical method as it has evolved through these studies.

ABSTRACT

This paper describes a method for calculating long-run marginal costs for an electric utility. The method is especially suitable for computing the marginal costs associated with the use of small on-site energy technologies -- i.e., cogenerators, solar heating and hot water systems, wind generators, etc. -- which are interconnected with electric utilities. In particular, both the costs a utility avoids when power is delivered to it from a facility with an on-site generator and the marginal cost to the utility of supplementary power sold to the facility can be calculated. A utility capacity expansion model is used to compute changes in the utility's costs when loads are modified by the use of the on-site technology. Changes in capacity-related costs and production costs are thus computed in an internally consistent manner. The variable nature of the generation/load pattern of the on-site technology is treated explicitly. The method yields several measures of utility costs that can be used to develop rates based on marginal avoided costs for on-site technologies as well as marginal cost rates for conventional utility customers.

INTRODUCTION

Until recently, virtually all retail electricity prices in the United States were determined by computing a utility's annual "revenue requirement"* and then allocating these costs to various customer classes based on assumptions regarding each class's share of the incurred costs. Most utility rates are still set by such a method. Although this approach to pricing is convenient from a regulatory viewpoint, it does not necessarily encourage the most economically efficient use of electricity; consumers of electricity are provided with pricing signals that tell them a great deal about the accumulated historical costs of producing power, but little about current trends in costs.

The economic literature has for several decades included discussions (and disputes) regarding the application of marginal cost pricing principles to regulated utilities. Until the past few years, these discussions were treated by regulators as being primarily of academic interest. Energy shortages and rapid price increases, however, sharply heightened interest in providing better market signals to consumers of electricity than were being provided by traditional approaches to pricing.

At the same time, the economics of decentralized power production were improving. The interconnection of privately owned power producing devices with utilities and the rates for the interchange of power between the two became serious issues. In 1978, the Public Utility Regulatory Policies Act (PURPA) became law and significantly altered the regulatory treatment of small on-site energy technologies. The Act required utilities to buy power from and sell power to qualifying on-site generators. PURPA also established federal standards governing the pricing of electricity. These standards have been widely interpreted as requiring that marginal cost pricing principles be applied to the design of electricity rates.

There is no general consensus at this time regarding precisely how marginal cost pricing theories should be translated into functional methods and models for computing rates. With respect to rates for interchanges of power between utilities and private producers, the problem of computing appropriate rates becomes further complicated since the power provided by the private producers and the supplementary power required by them may be unusually variable in character (depending, for example, on wind or solar availability).

In this paper we report on a method for computing marginal costs that has been developed at Brookhaven National Laboratory. This method computes long-run marginal costs and is suitable for analyzing the marginal costs and values associated with power interchanges between the utility and a private power producer, including situations in which the generation/load pattern of the latter is variable.

*The sum of the costs the utility is entitled to recover from its customers composed of its current running costs, carrying charges for plant and equipment, administrative overhead, taxes, insurance, customer service-related costs, etc.

BACKGROUND

PURPA and the FERC Rules

Before the 1970's, the real price of electricity in the United States declined as advances in the technology of power production and the economies of scale experienced with constantly increasing plant sizes significantly reduced the costs of generation. Simultaneously, private generation of power gradually declined as a percentage of total power production as more and more consumers of electricity found it cheaper to purchase power from utilities than to produce it themselves. Regulation actively promoted this trend by severely limiting the conditions under which privately generated power could compete with that produced by franchised utilities.

The dramatic increases in the prices of oil and gas in the 1970's and the almost equally dramatic increases in the costs of power plants, especially nuclear and coal, have changed this situation. Today, cogeneration, solar space and water heating, wind power, and small hydro turbines often offer an economical alternative to the production of electric power in large centralized plants. Generally speaking, the economics of these technologies and the opportunities for their exploitation are improved when they are interconnected with electric utilities; the sale of excess power to the utility can provide extra income to the facility owner and the need for redundant capacity and/or energy storage at the facility can be reduced since the utility can provide supplementary or backup power.

PURPA was designed, in part, to eliminate regulatory barriers to such interconnection. The Act exempted cogenerating and small power producing facilities with generating capacities less than 30 MW from both state and federal regulation, as power producing utilities provided they used solar, wind, biomass, and hydro energy inputs. (The status of cogenerating equipment using other fuels was left to the Economic Regulatory Administration [ERA] for later determination.) From a national energy policy perspective, the use of such technologies is desirable since they conserve oil and gas resources and, insofar as they are cheaper than new utility generation, their use increases the overall economic efficiency of energy production. PURPA required that the Federal Energy Regulatory Commission (FERC) establish rules "as it deems necessary to encourage cogeneration and small power production" [Sec. 210]. These rules were to require electric utilities to purchase electricity from qualifying facilities and to sell power to them. They were also to ensure that the rates for such sales and purchases not discriminate against the qualifying facilities, and that they be "just and reasonable to the electric consumers of the electric utility and in the public interest" [Sec. 210].

PURPA established the following standard with respect to rate designs:

Rates charged by any electric utility for providing electric service to each class of electric service shall be designed, to the maximum extent practicable, to reflect the costs of providing electric service to such class... [Sec. 111d].

With respect to the standard concerning costs of service, ... the costs of providing electric service shall, to the maximum extent practicable, be determined on the basis of methods prescribed by the State Regulatory Authority....Such methods shall to the maximum extent practicable

- (1) permit the identification of differences in cost-incurrence, for each class of electric customers, attributable to daily and seasonal time of use of service, and
- (2) permit identification of differences in cost-incurrence attributable to differences in customer demand, and energy components of cost. In prescribing such methods, such state regulatory authority...shall take into account the extent to which total costs to an electric utility are likely to change if
 - A) additional capacity is added to meet peak demand relative to base demand; and
 - B) additional kilowatt-hours of electrical energy are delivered to electric consumers. [Sec. 115(a)].

Although the term "marginal cost pricing" was not employed in the PURPA legislation, the rate design standards in Sec. 115a have been widely interpreted as requiring the application of marginal cost pricing principles. In its "Guideline #2 Under the Public Utility Regulatory Policies Act of 1978: Solar Energy and Renewable Resources in Relation to the II PURPA Standards," the ERA interpreted PURPA in this way. (In this same document, the ERA also interpreted PURPA as requiring that rates for supplementary power for residential solar heating be nondiscriminatory and that this could be achieved if rates were based on marginal costs.)

In its Order No. 69, "Small Power Production Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978," the FERC, in accordance with the above mandates, established rules and procedures to be implemented by state public utility commissions regarding the interconnection of electric utilities and cogenerating and small power production facilities. The order states that tariffs for these facilities should be based on full "avoided costs." In essence, the FERC ruled that tariffs had to be devised in such a way that the utility pays to the facility owner the full amount of all costs the utility avoids if the facility owner generates power in a device connected to the grid. Both production ("energy") costs and capacity costs must be considered in computing the costs avoided. For cogenerators and small power producers that also consume electricity, the FERC Order permits arbitrage; i.e., the facility owners can, if they wish, continue to purchase all of the electricity they consume from the utility at previously established rates for the consuming class of which they are a member and simultaneously sell all of the power they generate to the utility at the new "avoided cost" tariffs.

Although this procedure may initially seem odd, it achieves an important goal implicit in PURPA; it places new privately generated electricity on an equal footing, economically, with new utility generation. That is, the price the facility receives for the electricity it generates is equal to the utility's cost of electricity at the margin. The reasoning was that, by allowing the facility to sell all of its generation to the utility at full marginal cost rates while continuing to allow it to purchase electricity at rates appropriate for the customer class of which it would otherwise have been a member, the Commission was fulfilling its mandate under PURPA ("permitting simultaneous purchase and sale is necessary and appropriate to encourage cogeneration and small power production" [p. 49 of commentary accompanying Order No. 69]). The benefits of the simultaneous buy/sell scheme, in terms of encouraging the use of cogenerating and small power production facilities, are illustrated by the following example: If the marginal cost of utility generation were substantially higher than the average cost and conventional tariffs were based on average costs (a common situation today), the attractiveness of private generation would be much less if a facility received only average cost based prices for its power or if it could sell to the utility only the power in excess of its internal consumption than if it could engage in arbitrage.* In either of the first two cases, one would expect the use of alternative technologies to be less than if the FERC approach were followed.

Marginal Cost Pricing

Neither PURPA nor the FERC's Order No. 69 for cogenerating and small power production facilities are complete prescriptions for tariff design. Basic principles have been laid out and certain limits have been set regarding what can be considered an acceptable approach. Within the limitations, there are a number of possible approaches to rate design that would satisfy PURPA and FERC requirements.

Whether one is developing avoided costs for cogenerating and small power production facilities or nondiscriminatory rates for backup to solar energy systems, the computation of marginal costs is required. However, there is no single, universally accepted functional definition of marginal costs. Several methods have been developed to compute marginal costs for use in designing rates.¹ Although all compute "marginal costs", they differ not only in their computational procedures but also in the implicit conception of marginal cost. Among the differences in the methods are whether short- or long-run costs form the basis for the analysis, the treatment of capacity costs, and whether the marginal costs are computed by time period or by customer class. To help elucidate the Brookhaven approach, we will briefly discuss these differences.

*Note, however, that there is no advantage to the simultaneous buy/sell approach if the utility's conventional tariffs are based on full marginal costs (rather than on average costs or on revenue-adjusted marginal costs). In this case, assuming tariffs have been properly designed, the facility owners should be indifferent between the simultaneous buy/sell treatment of their purchases and sales of electricity and the more traditional net buy/sell treatment.

Short-Run vs Long-Run Costs. Micro-economic theory indicates that under certain conditions economic efficiency is maximized when all pricing is based on short run marginal costs. In the case of an electric utility, this can be narrowly interpreted as requiring that prices be based only on instantaneous marginal production costs (system lambdas). In practice however, this restrictive interpretation is virtually impossible to apply in most situations and practical approaches to marginal cost pricing generally adopt a broader interpretation of the theoretical result.² For example, rather than using instantaneously varying marginal costs, the year is divided into only a few time periods and prices are based on the average of the marginal production costs over the time periods. Also, marginal capacity costs are generally incorporated into the price in some way.

With regard to the development of rates for cogenerating and small power production facilities, the FERC Order No. 69 explicitly states that the avoided cost must include savings in both marginal production and marginal capacity costs: "'Avoided costs' means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source" [p. 113, Order No. 69]. Hence, basing rates only on avoided short-run costs is not permissible.

The components of the avoided cost can be calculated either in the short run or in the long run. Short- and long-run production and capacity costs have been combined in three different ways in various approaches to marginal cost analysis as illustrated in Figure 1. In one approach, short run production costs are combined with short run capacity costs. This approach has the virtue of simplicity (at least compared with the others); system lambdas can be obtained from a simulation model, or recent actual system lambda data can be used, yielding the short-run production costs with a minimum of effort. However, since changes in capacity typically require long lead times, what meaning can be given to the term "short run capacity cost"? One solution to this dilemma is to substitute a "curtailment cost" (i.e., the costs of a blackout or the "short-run" response to the realization that a blackout has become very possible) for the actual capacity costs being incurred by the utility. For example, it can be argued that a utility could, at least theoretically if not in actuality, purchase a small peaking unit on short notice if load growth warranted it; hence the cost of the peaker could be said to be the short-run cost of capacity.

A problem with this approach is that the hypothetical peaker unit is probably not the utility's best choice of capacity (it may not even be a conceivable choice); although the peaker may theoretically represent a utility's emergency response to an unexpectedly sudden growth in load, it is unlikely to represent the utility's actual response to normal changes in load growth except in special cases. Hence, the sum of the components of the marginal costs computed in this way is not necessarily representative of actual power costs either in the present or in the future. Although justifications have been offered for the use of the peaker surrogate, they are not completely convincing since they require conditions

PRODUCTION COSTS			SHORT RUN	LONG RUN
C				
A		SHORT		
P	C	RUN	SS	—
A	O			
C	S	LONG		
I	T	RUN	LS	LL
T	S			
Y				

	<u>CAPACITY</u>	<u>PRODUCTION</u>
SS	Peaker or other surrogate	Short-run variable costs
SL	Long-run changes in purchase schedule	Short-run variable costs
LL	Long-run changes in purchase schedule	Long-run variable costs

Figure 1. Approaches to marginal cost computations.

not experienced in the real world.* Another problem with this approach is that the analytical framework does not provide a firm basis upon which capacity costs can be assigned to electricity use other than to peak use. Since changes in non-peak use can affect future expenditures for capacity, this is a significant deficiency.

An alternative approach is to combine long-run capacity costs with short-run production costs to compute the total marginal cost (see, for example, Turvey³). In this hybrid approach, long-run capacity costs are computed in one of two ways: 1) The completion dates of specific plants in the capacity expansion plan are shifted using a judgmental approach,⁴ or 2) optimal shifts in the capacity expansion schedule are computed using a capacity expansion model of the type used for planning purposes. In the second approach, the model is run both with and without the hypothetical load modifications to yield the changes in capacity purchases.

*A defense that has been made of this approach to the treatment of capacity costs is that, if the utility is in an optimal state, then adding the cost of a peaker to the short-run variable costs yields correct total marginal cost whether or not it is an actual purchase option. Since the utility that is in an optimum state today is a rare beast indeed, the validity of this argument is highly questionable.

In either case, the present value of the changes in long-run costs associated with changes in the capacity purchase schedule is computed, levelized, and added to the short-run production costs to yield a total marginal cost.

A complication that arises in applying this approach is that the long-run capacity costs should be adjusted for differences between the production costs associated with the future capacity and the production costs associated with the capacity giving rise to the short run production costs. Otherwise, one could, for example, be adding high current short-run costs associated with oil-fired power plants with high long-run capacity costs associated with nuclear or coal plants to yield a sum which is significantly higher than the costs a utility currently incurs or can realistically be expected to incur in the foreseeable future.* This adjustment, if performed properly, can add substantially to the complexity of the calculations.

In the third approach, long-run marginal costs are computed; i.e., both production and capacity costs are computed in the long-run. A capacity expansion model incorporating a production costing routine that is capable of responding directly to load pattern modifications can be used to perform the required computations. As with the other approaches a time period or a specific load pattern is defined for which the marginal cost is to be computed. The model is then run both with and without the defined changes in load and the difference in the costs between the two cases, divided by the change in generation, is the desired long-run marginal cost. In this way, a realistic estimate is obtained of the actual changes that are likely to be experienced in utility capacity and production costs as a result of load changes. In its Order No. 69, the FERC specifically cited this approach as an acceptable method for computing avoided costs.

Although the computational procedures required in this approach may be more elaborate than those employed in the other two,* the short-run capacity cost issue is eliminated and the levelizing and adjustment process is not required. The long-run marginal cost approach has been adopted in the method described in this paper.

Time Period vs Customer Class. Marginal costs can be defined either by time periods, irrespective of the generation/load pattern of the customers involved, or by customer class in which case the timing of electricity generation or use can be ignored. When the former approach is employed, rates are generally specified by time of day, week, and season. The advantage of this approach is that the customer's pattern of generation/load need not be considered in developing rates. Instead, rates for all classes are based on the cost consequences of changes in load during the defined time periods independently of whether or not a particular rate class is itself responsible for causing changes in the utility's costs during that time period.

*But not necessarily more so than the hybrid approach when the adjustment is performed properly.

The other approach is to compute class-dependent marginal costs; i.e., the daily and seasonal generation/load pattern for a class of customers is determined and the changes in utility costs that result when utility loads are modified due to the addition of such a class of customers are computed. In this way, the tariff can be tailored to the specific generation/load pattern of a particular class. A class-differentiated tariff need not be further broken down by time periods. Although it is impractical to compute marginal costs for every conceivable load pattern, class-dependent marginal costs can be employed in those cases in which the load of the class is large and in which the individual members have very similar load patterns. In addition to forming the basis for rate design, class-dependent marginal costs can be used to check that any existing or proposed marginal cost-based rate structure does, in fact, result in the proper schedule of payments to a particular class.

The time-differentiated and class-differentiated approaches to rate design can be combined: The latter can be employed for classes of very similar customers composing a large fraction of the utility load while the former can be used when the classes combined load is too small to justify a separate class-dependent cost analysis or when the class is composed of disparate members.

DESCRIPTION OF THE METHOD

General Outline

As mentioned above, the approach to marginal cost analysis we selected examines changes in long-run costs. The method has been designed to be suitable for computing class-differentiated marginal costs associated with privately owned energy systems but can also be used to compute time-differentiated marginal costs. The method involves computing changes in the stream of future annual or seasonal revenue requirements that result from load modifications. In computing future revenue requirements, a capacity expansion model incorporating a production costing code which operates on hourly load data is used to determine the changes in capacity additions and in production costs that result when utility generation requirements are changed because of the introduction of new technologies. The change in revenue requirements divided by the change in utility generation is defined as the desired marginal cost.

The general conception of the approach is illustrated in Figure 2. The method of analysis is illustrated in detail in Figure 3 and outlined in Chart 1.

If the method is being used to compute time-differentiated rates, a series of load modifications are considered, each one of which is simply an incremental change in the load during a specified period of the day, week, and year. If a class dependent rate structure is being developed, then the load modifications are derived from the pattern of generation and/or load associated with the new technology under consideration.

Figure 2. Simplified outline of method.

There are three basic elements of the computational procedure: facility simulation, utility capacity planning and production cost analysis, and the comparative cost and fuel-use analysis. These are described in more detail in the sections that follow.

Facility Simulation

Simulation Models. If class-differentiated avoided costs are being computed, detailed generation/load data for the facility in question are required. Ideally, actual operating data should be used but, in practice, these are rarely available today. As the use of privately owned generating facilities grows, operating data appropriate for cost analysis can be expected to become available for a variety of cogenerating and small power-production facilities located in a variety of operating environments. Until such time, however, the behavior of such facilities can be simulated using a number of computer models developed for this purpose in the last few years.

Facility models currently in use at Brookhaven National Laboratory include:

DOE - 2	-- Cogeneration in commercial buildings
TRNSYS	-- Active solar heating and hot water in residences
DEROB	-- Passive solar heating in residences
PVSOLSYS	-- Photovoltaic systems performance

Figure 3. Detailed schematic of the method.

CHART 1

OUTLINE OF THE METHOD OF ANALYSIS

- (1) Identify pattern of electrical generation and/or load of new technology; i.e., hourly pattern for entire year.
 - a. E.g., i) for residential solar hot water system, identify the pattern of backup electricity requirement; ii) for cogeneration, identify the pattern of electricity generation.
 - b. Where available, actual data from real systems can be used. Otherwise, simulation models are available for estimating the performance of many new technologies.
- (2) Compute future annual or seasonal revenue requirements for utility assuming new technology is not introduced (base case).
 - a. Use capacity expansion model with embedded production costing routine.
 - b. Assume established load forecasts, capacity options, and costs.
- (3) Modify load forecast assuming new technology is introduced.
 - a. Assume one or more market penetration projections.
- (4) Compute future annual revenue requirements with modified load.
 - a. Reoptimize of capacity expansion schedule.
- (5) The change in revenue requirements from the base case to the modified case is the incremental cost (value) to the utility of the incremental load (generation due to the introduction of the new technology).
 - a. The capacity cost and production cost components of the change in revenue requirements can be separately identified.

The building simulation models all function in a similar manner: Given input data regarding the building's structure, its HVAC system, its occupancy and appliance use schedule, the characteristics of the on-site energy technology of interest, and weather data, the model determines the hourly electrical and/or thermal loads as appropriate. It then schedules the operation of the on-site device to meet these loads. The model typically provides an hourly tabulation of the energy consumed by and produced by the device (including supplementary electricity, if appropriate).

The photovoltaic system simulation models are simpler and compute only the electrical output of the device as a function of the hourly solar radiation.

A number of simulation runs are typically required to provide the data needed in evaluating the economics of different device configurations and sizes. The configuration with the best economics is generally selected as the most likely to be introduced into the marketplace. The hourly output of the simulation model is combined with market penetration projections and, where appropriate, a diversity correction to yield the modifications to the utility's load.

Facility Reliability. The facility simulation inherently accounts for the variability in the output of the on-site energy technology to load patterns at the facility and due to weather patterns. However, this simulation does not account for breakdowns which, of course, can reduce the output of the device in a stochastic manner.

If outages due to breakdowns can significantly affect the cumulative generation/load pattern of large devices, the following adjustment can be made: Assume that the outage probability for each individual unit is known and that it is uniform over the time the device is actually run. If each facility consists of a number of identical on-site energy producing units (e.g., a facility using five identical diesel cogenerator sets) the simulation model can be repeatedly run assuming first that all of the units are functioning, then, that one of them is unavailable, etc. A probability weighted sum of the resulting streams of hourly data is then computed. If there are a large number of such facilities, the result is a reasonable representation of the cumulative load pattern experienced by the utility.*

Market Penetration Projections

A utility's costs can be affected not only by the pattern of the change in its load but also by the magnitude of the change. Consequently, it is important to test the effects of different market penetrations of the on-site technology. A range of projections is needed to reflect the uncertainty in estimates of the actual penetration; usually two or three projections suffice. On the high side, penetration levels are selected that are high enough to capture possibly adverse effects on

*If the number of facilities is small, the result is not a good representation of the loads. However, in this case the overall effect of the outages on the utility is so small that the issue is moot.

planning and dispatch but not higher than a market potential analysis indicates is feasible. On the low side, the projection must not be so low that the resulting changes in load patterns are too small to significantly affect utility operations. We have found in our applications work that market penetration projections that change loads by less than 1% (i.e., the change in total annual generation) still produce internally consistent marginal cost results.

Capacity Planning and Production Cost Analysis

General Description. The Wien Automatic System Planning Package (WASP)⁴ is an integrated sequence of computer programs designed to find an optimal generation expansion plan for an electric utility. A dynamic programming algorithm determines the schedule of plant purchases and retirements which minimizes the present value of future capital and operating costs. A probabilistic production costing routine is used to develop operating costs and reliability measures.

WASP evolved from the System Analysis Generation Expansion (SAGE) program at the Tennessee Valley Authority (TVA). Modifications to SAGE by the Oak Ridge National Laboratory and the International Atomic Energy Agency (IAEA) resulted in the current program. Since its introduction in 1974, WASP has been extensively used by the IAEA in power planning studies around the world and has been adopted by many utilities in the U.S. TVA's policy has been to make the WASP code and subsequent modifications freely available, and a users group is active.

The WASP package is comprised of six modules which allow user intervention and evaluation at all steps of the optimization. In one of the modules, the utility system under study is described on a plant specific basis with current fuel costs and operating characteristics. Future additions and retirements to which the utility is absolutely committed are also specified. In a second module, all possible options for future capacity additions are described; each capacity alternative is characterized by size, fuel type, heat rate, and reliability. Hydroelectric power, both run-of-the-river and emergency, as well as pumped storage plants may be analyzed by the code either as part of the existing system or as options for the future.

In using WASP, a study period (usually five to twenty-five years) is defined. Each year can be divided into periods if desired; 12 periods is the maximum possible number of periods per year. A load forecast including, at a minimum, peaks and energy use for each period is obtained. Load duration curves are computed from these forecasts and the historical load pattern. Future costs, capacity options, desired reliability levels, and a discount rate are identified. WASP is then run to yield the optimal capacity expansion schedule.

The data required for the planning and production cost analysis in Brookhaven's modified version of WASP are shown in Chart 2. These data are generally available at the utility since they are required for rate and planning studies. In many cases, public utility commission require the publication of these data.

CHART 2

DATA REQUIREMENTS

Hourly load data for recent year

Load forecast (preferably giving seasonal peak loads and load factors)

Existing utility plant including available capacity, heat rates, and variable costs.

Reliability constraints

Purchased power projections

Required capacity additions (i.e., with no changes in schedule possible)

Capacity options specified by cost plant type, size, earliest date of completion

Current revenue requirements

Fixed charge rate

Fuel cost trajectories

Future Capacity Options. The selection of capacity expansion options is at the discretion of the user; the selection must be sufficient for reserve margin requirements but must be limited to a computationally reasonable number. Of course, the options must reflect those choices which the utility can realistically make in the study time frame. The capacity expansion options are specified as upper and lower bounds on the (discrete) number of each alternate plant type which may be built in each year of the study period. Inherent in the dynamic optimization procedure of the WASP code is this requirement for discrete capacity additions; this is consistent with the actual utility expansion process in which capacity additions are "lumpy" over time.

Production Cost Simulation. The simulation module of WASP calculates production costs for every possible combination of the permitted capacity options. For each year of the study period, a Baleriaux-Booth simulation algorithm computes expected generation by each plant using the seasonal load duration curves. This algorithm explicitly accounts for the scheduled and forced outages of all units and calculates the expected loss-of-loading-probability (LOLP) for the system. Generating units are represented in two blocks so that minimum loading levels and spinning reserve requirements are observed. Hydroelectric capacity is divided

into baseload and emergency power to accurately reflect the operation in a particular system. Pumped storage, if included, is optimally placed in the loading order so as to maximize cost savings subject to the designed energy capability of the facility.

Reliability. System reliability is measured by both LOLP and expected unserved energy. We modified the WASP code to charge an operating cost penalty for the unserved energy; this cost penalty is based on the price the utility would expect to pay for emergency purchases of power. This modification allows the optimization procedure to, in effect, find the cost-optimal level of reliability for the system within general constraints on reserve margins.

Optimization Procedure. In the dynamic programming module of WASP, the annual production costs for each generation expansion possibility are combined with capital costs associated with the expansion schedule. The capital costs of new generation alternatives are levelized using an annual fixed-charge rate appropriate for the utility. The fixed charge rate includes the cost of money for new projects and allowances for depreciation, insurance, and property taxes. It is assumed that interest payments during construction are capitalized and that no new plant enters the rate base before completion. Changes to the utility's rate base which are not discretionary -- such as retirements and committed new plants -- do not affect the optimization and are handled separately in the rate analysis model. No decommissioning costs beyond the study horizon are included.

A procedure based on Bellman's principle of optimality is used to find the capacity expansion path which minimizes the net present value of all future capital, operating, and overhead expenses. The discount rate and the general inflation rate used in computing the net present value are consistent with the cost of money included in the levelized fixed charge rate. The optimum path can be constrained to desired levels of reliability based on LOLP and by ceilings on the feasible rate of capacity purchases. Suboptimal solutions close to the optimum may be examined to see if they are preferable when other factors are considered.

Cost Summary. The final element of the WASP sequence is a cost summary code which includes information on capital outlays and fuel expenses. We have replaced this module with a code developed at BNL (the "Cost and Fuel Analyzer") that calculates revenue requirements and fuel use for each year of the study period for the optimal path, and computes changes in costs and changes in fuel use between different cases. The marginal costs are derived directly from this information. This procedure is described in more detail below.

Analyzing the Impact of Load Modifications

To compute the cost consequences of modifying a utility's loads, WASP is run both with the original unmodified load and with the modified load. The unmodified load -- the "base load projection" -- is a multi-year sequence of hourly loads derived from historical load data and forecasts of monthly peak loads and monthly energy use. Hourly utility

load data for at least one recent year form the basis of the projected base load data. To correct for weather-induced load variations (other than those associated with the facility under study), the historical load data are selected so as to be coincident with the historical weather data used for the facility simulation. The historical load data are combined with the monthly peak and energy use forecasts by a code ("Load Scaler") which adjusts the historical hourly loads so as to correspond to the pattern and magnitude implied by the forecast.

The modified load projection is obtained by adjusting the base load projection in accordance with actual facility generation/load data or with data from a simulation model. A computer code (the "Load Modifier") developed at BNL performs a series of computations to accomplish this. The hourly facility load data are first corrected for class diversity, if appropriate, by using a Gaussian moving average smoothing technique. Then for each year of the study period, the code multiplies the data by the market penetration level for that year and combines the resulting data stream with the base load projection to produce the modified load projection.

The Load Integrator code (obtained from TVA) takes the base or the modified load projection and computes load duration curves for each period of each year. Four load duration curves per year are generally used, but monthly curves can be developed where needed for detailed rate analyses. Within WASP itself, the load duration curves are represented by a Fourier series. The series coefficients are computed directly from the hourly data by the Load Integrator code. These coefficients are then fed into the WASP model. For the base case and for each modified case, WASP is run to find the optimal expansion path and the associated utility costs and fuel-use patterns.

The Cost and Fuel Analyzer code extracts the operating and capital cost data associated with the optimal expansion from the WASP model. The code applies a fixed-charge rate, appropriate for each utility, combining the return on investment, taxes, and depreciation to the rate base to compute the capacity-related costs. These are then added to the production costs, the administrative and overhead costs, and those transmission and distribution costs that are not directly allocated to new generation capacity. From these financial data a stream of annual (or seasonal) revenue requirements is computed. Comparisons among the revenue requirement streams for different cases yields the desired marginal cost and fuel use information. For example, the marginal cost (or savings) associated with a load modification is simply the difference in the revenue requirements between the modified case and the base case divided by the difference in total electricity generated.

Format of Results

In its current form, the Cost and Fuel Analyzer code provides a tabulation of a variety of load, cost, generation mix, and fuel parameters. Generally, four or five runs are combined into a set which is run through the code. Each set would typically consist of a base case,

several modified load cases, and an "incremental growth" case in which the rate of normal load growth is varied. (This case is used to compute the long run marginal cost of normal load growth, a useful reference measure of the trend in the utility's long-run costs. In constructing a marginal cost-based rate structure, this parameter is as significant as the utility's average cost.)

The output file contains results for each case in a set and the differential costs and fuel use between each modified case and the base case. Except for certain cumulative parameters, all results are shown for each year of the study period. Three-year moving averages and ten year means are also provided where useful. The output is in an easily understood table format. In addition, a graphics routine has been developed to provide bar charts and plots of the time trends in cost and fuel-use indices. A partial listing of the contents of the output file is provided in Chart 3. An example of the case data output is shown in Table 1. Examples of the graphics output are shown in Figure 4.

APPLICATIONS

The method of analysis just described has been applied in four case studies.^{5,6} In three of these studies, the marginal cost to three U.S. utilities of providing backup to solar heating and hot water systems was computed. In each of these three studies, the marginal cost of the load due to electric-only heating and hot water devices and the marginal cost associated with load managed solar and electric heating and hot water devices were also computed.

In the fourth study, the marginal costs and savings associated with commercial cogeneration (office and apartment buildings) in the service territory of the Consolidated Edison Company were investigated. In addition to computing the avoided cost associated with the gross output of a cogeneration device (i.e., for the simultaneous buy/sell situation), other marginal cost parameters were also computed: the avoided cost associated with the net sale of power to the utility; the marginal cost of supplementary power; and the marginal cost of meeting the building's normal load. The results of this study have been used in a generic on-site generation rate case by the staff of the New York State Public Service Commission in assessing the long-term impacts of cogeneration on Con Ed.

The method is thus a flexible tool for computing marginal costs and values for a variety of on-site energy technologies as well as the marginal costs for conventional customer classes. Although the emphasis in this report has been upon class-differentiated marginal costs, time-differentiated marginal costs can also be computed by substituting uniform load changes during specified time periods for the load modification due to an on-site technology.

CHART 3

OUTPUT DATA OF THE COST AND FUEL ANALYZER

(Unless specified, each parameter is computed for each year of the study period.)

Case Output*

Production costs and fixed costs

Revenue requirements

Present value of revenue requirements computed at 2, 4, 6, & 10% discount factors

Peak load

Load factor

Generation broken down by unit type

Installed capacity broken down by unit type

Reserve margin

Annual and cumulative fuel use broken down by fuel type

Differential Output†

Marginal cost broken down by capacity and production cost components

Incremental annual cost (or savings) per facility broken down by capacity and production costs components

Incremental fuel use per facility broken down by fuel type

*For every case studied in a set, including the base case.

†Comparison between each modified load case and the base case.

TABLE 1
LOAD AND COST DATA

YEAR	PEAK LOAD	ANNUAL GEN	ANNUAL LOAD FACTOR	RESERV MARGIN	PROD ANNUAL	COST UNIT	CAPITAL ADDITIONS		COST CUMUL	TOTAL COST	
	(MW)	(GWH)	(%)	(%)	(E6)	(C/KWH)	GEN (E6)	T&D (E6)	UNIT (C/KWH)	ANNUAL (E6)	UNIT (C/KWH)
1980	8055	38468	54.5	43.0	1471	3.83	0	0.0	3.20	3213	8.35
1981	8227	39145	54.3	39.6	1444	3.69	0	111.3	3.23	3216	8.22
1982	8377	39750	54.2	37.1	1404	3.53	0	97.1	3.27	3212	8.08
1983	8515	40331	54.1	34.6	1391	3.45	0	89.3	3.31	3235	8.02
1984	8620	40862	54.1	32.4	1330	3.26	0	74.4	3.30	3191	7.81
1985	8753	41399	54.0	30.5	1382	3.34	0	79.6	3.30	3260	7.87
1986	8817	41708	54.0	29.3	1426	3.42	0	41.4	3.30	3313	7.94
1987	8878	42016	54.0	32.5	1434	3.41	185	39.5	3.39	3370	8.02
1988	8928	42308	54.1	31.8	1581	3.74	0	32.4	3.39	3525	8.33
1989	8977	42498	54.0	30.7	1626	3.83	0	31.7	3.39	3577	8.42
1990	9014	42639	54.0	40.2	1478	3.47	852	23.9	3.83	3621	8.49
1991	9050	42787	54.0	39.6	1504	3.52	0	23.3	3.83	3652	8.54
1992	9072	42912	54.0	39.3	1528	3.56	0	14.2	3.83	3679	8.57
1993	9113	43073	54.0	38.7	1555	3.61	0	26.5	3.82	3712	8.62
1994	9141	43184	53.9	36.2	1579	3.66	0	18.1	3.82	3740	8.66
1995	9167	43300	53.9	41.1	1550	3.58	284	16.8	3.97	3777	8.72
1996	9180	43394	54.0	33.4	1534	3.54	0	8.4	3.93	3749	8.64
1997	9211	43521	53.9	30.3	1530	3.52	0	20.1	3.91	3743	8.60
1998	9231	43604	53.9	30.0	1539	3.53	0	12.9	3.91	3755	8.61
1999	9251	43707	53.9	29.7	1550	3.55	0	12.9	3.91	3769	8.62
2000	9262	43805	54.0	26.3	1556	3.55	0	7.1	3.89	3770	8.61

NOTE RESERVE MARGIN INCLUDES FIRM HYDRO CAPACITY OF 780 MW

CAPACITY, GENERATION, AND FUEL USE DATA

YEAR	INSTALLED CAPACITY (MEGAWATTS)					ENERGY OUTPUT (GIGAWATT-HOURS)						FUEL CONSUMPTION		
	COAL TURB	OIL-STEAM	COAL	NUCL	PUMP STRG	COAL TURB	OIL-STEAM	COAL	NUCL	HYDRO	PUMP STRG	DIST	(E9 BTU)	
													RESID	COAL
1980	1812	6945	0	1980	0	197	20664	0	12509	4400	0	2986	223441	0
1981	1812	6073	872	1950	0	372	17910	3508	12250	4400	0	5658	194771	38191
1982	1812	5738	1207	1950	0	387	15668	6374	12220	4400	0	5899	170313	68415
1983	1812	5277	1668	1920	0	533	13745	8920	12018	4400	0	8114	150325	94858
1984	1812	5277	1668	1890	0	265	12548	9281	11675	6400	0	4033	136237	98121
1985	1812	5277	1668	1890	0	313	12910	9372	11717	6400	0	4762	140512	99054
1986	1812	5277	1668	1860	0	351	13248	9459	11568	6400	0	5348	144489	99948
1987	1812	5277	1668	1830	400	195	13225	10249	11601	6400	1006	2969	142881	107976
1988	1812	5277	1668	1830	400	442	14912	16648	11620	4397	1197	6695	161672	112065
1989	1812	5277	1668	1800	400	502	15198	10697	11432	4397	1229	7594	164866	112564
1990	1812	5277	2568	1800	400	127	11616	14715	11400	4397	895	1922	126327	153570
1991	1812	5277	2568	1800	400	135	11736	14751	11402	4397	900	2043	127677	153933
1992	1812	5277	2568	1800	400	140	11832	14763	11401	4397	892	2129	128720	154054
1993	1812	5277	2568	1800	400	150	11942	14811	11404	4397	895	2283	130000	154539
1994	1812	5277	2568	1800	400	157	12016	14834	11404	4397	904	2383	130851	154775
1995	1812	5277	2868	1800	400	104	11007	16055	11389	4397	934	1586	119870	167295
1996	1812	4549	2868	1800	400	152	11039	16061	11388	4397	964	2323	120021	167363
1997	1812	4339	2868	1800	400	165	11013	16224	11399	4397	994	2531	119417	169009
1998	1812	4339	2868	1800	400	170	11062	16243	11400	4397	991	2606	119947	169199
1999	1812	4339	2868	1800	400	177	11128	16261	11400	4397	986	2719	120654	169376
2000	1812	4039	2868	1800	400	290	11104	16264	11400	4397	983	4449	119615	169410

Figure 4. Examples of the Graphics Output.

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