THE APPROPRIATENESS AND FEASIBILITY OF VARIOUS METHODS OF CALCULATING AVOIDED COSTS

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FOREWORD

This report was prepared by The National Regulatory Research Institute (NRRI) under a contract with the West Virginia Public Service Commission (WVPSC). The opinions expressed herein are solely those of the authors and do not reflect the opinions nor the policies of either the NRRI or the WVPSC.

The NRRI is making this report available to those concerned with state utility regulatory issues, since the subject matter presented here is believed to be of timely interest to regulatory agencies and to others concerned with utility regulation.

Douglas N. Jones
Director

EXECUTIVE SUMMARY

Recent developments in federal law and regulatory rulings require the state public service commission to set rates for utility purchase of power from cogenerators and small power producers. The rates are to be based on the costs avoided by the utility because of its reduced need to generate electricity or to purchase power from another source.

An idealized method of calculating avoided costs is presented based on marginal costing concepts. It accounts for the avoided costs of generating capacity and of energy generation. To determine avoided costs, load forecasts and capacity expansion planning models are employed. The idealized method requires elaborate computer programs, access to computer facilities, and specialized personnel. Additionally, the idealized method is dependent on the collection of a rather extensive data base. These efforts are undertaken in an attempt to realize a high level of precision in estimates. While the theoretical appropriateness of the idealized method is perhaps its strongest point, the sophistication of its application may present limitations to public service commissions. This method may not be practical for a commission which has a limited number of personnel, limited data collection capabilities, or lacks access to computer facilities. For such a commission, the idealized method is a useful reference for judging other, more practical methods.

If data processing and data availability limitations did not exist, the avoided cost calculation would have the following features:

1. Revenue requirements do not increase as a result of purchasing power at avoided cost;

2. Avoided capacity costs reflect adjustments to the utility's expansion plan that are attributable to purchases from qualifying facilities;

3. Adjustments to the utility's normalized load curve is based on potential commitments of capacity on a firm and non-firm basis;

4. Potential commitments of capacity by qualifying facilities, regardless of the size of the commitment, are aggregated for purposes of adjusting the normalized load curve;

5. The avoided capacity costs reflect the change in the utility's income tax and property tax liability;

6. The avoided capacity costs are linked to changes in the operating costs experienced by the utility;

7. The payment of the avoided costs of capacity to qualifying facilities reflects the probability that the utility might experience demand that exceeds its available capacity;

8. The payment of the avoided costs of capacity to the qualifying facilities reflects the duration of a contractual commitment of capacity if that affects cost savings;

9. The commitment of capacity by a qualifying facility during a utility's system emergency is rewarded, and the reward reflects the avoided cost of reserve capacity; and

10. Avoided running costs reflect the hourly variation in system lambdas experienced by the utility or pool.

Of course, practical limitations result in not all these features being realized.

A number of practical approaches to calculating avoided costs, which provide results comparable to the idealized method, have been developed and are available for use by public service commissions. These approaches range from methods with complexity paralleling the idealized method to simplified methods which do not rely on computer capabilities or specialized personnel. These practical approaches include methods computing marginal cost as a proxy for avoided cost, using interutility purchased power rates as avoided cost based purchase rates, running the cogenerator's (or small power producer's) meter backward when that power supplier is also a utility customer, and computing large incremental changes in revenues or costs.

The various methods of avoided cost calculation differ in their theoretical appropriateness, conformance to legal requirements, and feasibility. Feasibility concerns the tradeoff between the additional costs of computers, computer time, and personnel associated with using the more analytical methods and the expected benefits of improved precision in the resulting estimates. For any particular commission, the costs of using the more analytical methods might outweigh the benefits of using these methods, and the potential benefits of using a more analytical approach might be limited by the potential for errors in forecasting.

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CHAPTER 1

INTRODUCTION

The National Regulatory Research Institute has undertaken this study as a part of its rate design and computer technical assistance to the West Virginia Public Service Commission concerning cogeneration and small power production rates and terms. The purpose of this study is to analyze the reasonableness and feasibility of various major avoided cost methods.

A brief introduction to cogeneration and small power production and the relevant FERC rules follows. A detailed discussion of the FERC rules is in appendix A.

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 potential for greater fuel utilization than is possible with a single-output system. The more general term "small power producers" refers to firms and individuals who generate limited amounts of electricity to meet their own needs or for sale to utilities.

Congress enacted Sections 201 and 210 of the Public Utility Regulatory Policies Act (PURPA) to encourage cogeneration and small power production. It requires utilities to purchase power at special rates and terms from cogenerators and small power producers that are qualifying facilities under rules promulgated by FERC. To qualify their facilities under these rules, cogenerators and small power producers must meet several conditions. The first condition for a cogenerator is that the cogeneration facility must meet minimum efficiency standards. The second condition concerns the ownership of the facility. Less than fifty percent of the facility's equity can be held by an electric utility or its affiliate; otherwise, the facility does not qualify. Small power production facilities, in order to qualify, must have a generation capacity less than or equal to 80 MW, must not utilize fossil fuel for more than twenty-five percent of their annual fuel usage, and must meet the same ownership criterion as qualifying cogeneration facilities. The FERC rules do not apply to cogeneration or small power production facilities whose construction commenced prior to the passage of PURPA on November 9, 1978. The FERC rules require state public service commissions to set standard rates for qualifying facilities with generating capabilities of 100 kW or less. However, the FERC rules are not intended to supercede existing or future voluntary contracts between co-generators or small power producers and utilities.

Under the PURPA Sections 201 and 210, state public service commissions are given numerous responsibilities concerning utility transactions with cogenerators and small power producers. These responsibilities include utility data collection requirements, setting rates for utility purchases from and sales to qualifying facilities, and estimating the interconnection costs of cogenerators and small power producers.

The FERC rules require state public service commission authorities to set rates for utility purchase of power from qualifying facilities. The rate must equal the cost avoided by the utility because of its reduced need to generate electricity or to purchase power from another source. An example of avoided costs follows. Utility A faces a load of 1000 MW. Because Utility A purchases electricity from cogenerators and small power producers, the utility faces a lower adjusted load curve. The utility can then take its less efficient, more expensive units off-line; and, if some of the power from the cogenerators and small power producers is firm power, Utility A can either delay construction of or reoptimize planned capacity. Assume that, because of these effects of purchasing power from cogenerators and small power producers, Utility A saves $1 million in costs it would have had <u>but for</u> its purchase of power from the cogenerators and small power producers. Then, this $1 million saving is the total "avoided cost" of purchasing power from the cogenerators and small power producers that is apportioned over the avoided output and avoided capacity of the cogenerators and small power producers. It is important to note that the avoided costs that are paid to the cogenerators and small power producers are the costs that the utility avoids, not the cost savings to the ratepayer. In principle, the ratepayer neither gains nor loses.

State public service commissions are expected to set standard rates governing utility purchases from qualifying facilities with generating capabilities of 100 kW or less. These standard rates may differ according to the type of generating technology employed. Each state public service commission determines the nature and extent of the utility cost data upon which these avoided costs are to be calculated.

The state public service commission also has the responsibility to determine the cost of interconnecting a qualifying facility with the utility system and to specify the manner and time period in which the qualifying facility will reimburse the utility for this interconnection cost.

The FERC rules give state commissions the responsibility to establish rates for the sale of supplementary, back-up, maintenance, and interruptible power service to cogenerators and small power producers. These rates must be just and reasonable and in the public interest. The rates may not discriminate against cogenerators or small power producers.

Many states have already set avoided cost rates under PURPA Sections 201 and 210. The next chapter contains a survey of the results of some of the state public service commission proceedings to set standard rates governing utility purchases from qualifying facilities with generating capabilities of 100 kW or less. State public service commissions have calculated avoided costs in a variety of ways.

The study is organized as follows. Chapter 2 of this study begins with some results of a survey of some cogeneration and small power production proceedings from other state public service commissions. A summary table of the state proceedings and documents from the survey are contained in appendix B. The nature of incremental and avoided costs is described in chapter 3. An idealized method of calculating avoided costs is also presented in chapter 3. Chapter 4 contains a discussion concerning cost-based deviations from the average annual avoided costs and presents an algorithm for their computation. The discussion also addresses deviations from avoided costs because of equity, distributive justice, or other concerns not related to the cost of service. Chapter 5 contains a discussion of the feasibility of the idealized approach and descriptions of several major practical methods of calculating avoided costs including a long-run marginal cost approach, a short-run marginal cost approach, the purchased power approach, the reverse-the-meter approach, the differential revenue requirement approach, and the simplified average incremental cost method. Chapter 5 also contains an analysis of each method's theoretical appropriateness compared to the idealized approach, as well as each method's feasibility, ability to fulfill the legal requirements of the Federal Energy Regulatory Commission (FERC) rules, and special problems. Chapter 6 summarizes the material and draws several conclusions.

CHAPTER 2

SURVEY OF STATE PUBLIC SERVICE COMMISSION PROCEEDINGS

Many state public service commissions are currently examining the issues involved in establishing purchase rates for power bought by a utility from cogenerators and small power producers. A few state public utility commissions have issued final orders regarding the methods to be used in estimating a reasonable avoided cost rate to be paid to cogenerators. Most state commissions have issued interim orders permitting experimental purchase rates to be offered while reserving final judgment on the best methods to be used in estimating the avoided costs associated with utility purchases from cogenerators.

A description of public service commission activities in a number of states is presented in this chapter on a state-by-state basis. The descriptions are based on some of the documents collected on an on-going basis by The National Regulatory Research Institute (NRRI) as a part of its Regulatory Information Exchange System.

Appendix B contains a table summarizing the status of state commission proceedings, as reported to the NRRI's Regulatory Information Exchange System on May 1, 1982. Because state contributions to NRRI's Regulatory Information Exchange System are not always complete, one should not necessarily conclude that a state public service commission has done nothing to implement the FERC rules based solely on the listings of the table in appendix B.

The state methods described in this chapter were selected by the authors to represent the diversity of perspectives that the state public service commissions and their staffs have on the proper means for calculating purchase rates. The state orders described in this chapter were chosen because of their distinctive features. In addition to orders, this chapter contains descriptions of staff papers provided to the California and Texas commissions. These papers provide examples of current research being done by the individual states on this topic.

Careful examination of the avoided cost calculation techniques described in this chapter reveals a multitude of factors that can be considered in adopting avoided cost methods. For example, in some states, the existence of excess generation capacity may be a significant concern. In other states, the estimation of avoided costs for a utility in a power pool may be of importance. The remainder of this chapter describes what several states have done or considered when adapting the concept of avoided cost pricing to suit the particular needs of their state.

Arkansas

The Arkansas Public Service Commission has issued proposed rules governing payments to cogenerators and small power producers. The commission's position is that the unique technical and business interrelations between a utility and each qualifying facility make case-by-case contract negotiation most appropriate in establishing payment rates for cogenerators. The guidelines established by the commission for the estimation of avoided costs are closely patterned after the relevant FERC rules. This approach allows the utility considerable latitude in selecting a particular avoided cost calculation method, since the guidelines specify a set of criteria for judging avoided cost based on rates and not a particular calculation method. Similarly, the standard rates for qualifying facilities with a design capacity of 1,000 kW or less are to be developed in conformity with the FERC standards.

In addition, the commission requires that utilities submit their modeling procedures, load forecasts, and the resulting expansion plans for a base case and for various levels of energy and capacity supplied by qualifying facilities. This information provides a means for evaluating the utility's estimate of the change in the aggregate system's fuel and operating costs, capital costs, and revenue requirements due to the expected output of qualifying facilities. This information is available for public inspection and presumably would be the basis for a negotiated rate. Utilities have the option of offering either a negotiated or a standard rate to qualifying facilities with a design capacity greater than 1,000 kW.

California

The California Public Utilities Commission has investigated in detail the use of avoided costs in establishing rates for cogenerators and small power producers. As a part of this investigation, a staff research paper was prepared which details the economic rationale for the public regulation of these purchase rates.

The paper takes the position that the monosony (i.e., single buyer) status of the utility makes the regulation of these purchase rates advisable. A utility's position as the only purchaser of this power gives it the bargaining power to pay cogenerators and small power producers less than what they would receive in a competitive market environment. The report contends that a qualifying facility payment based on a utility's marginal cost of providing service is a reasonable approach to the pricing of power purchased from cogenerators and small power producers. Since this power is being purchased at a rate equivalent to the utility's cost of producing it, the ratepayer is not made worse off by these transactions.

The report notes a significant hazard associated with requiring a utility to pay its marginal cost for power purchased from cogenerators and small power producers. When the rate charged by the utility for electricity is lower than its marginal cost, a qualifying facility could potentially install a loop allowing it to buy the utility's power and simultaneously sell it back to the utility at a higher price. In order to eliminate the potential for this type of profiteering, a second meter which measures the output of the qualifying facility is needed.

The paper also contains a discussion of illustrative purchase rates. For instance, the seasonal and time-of-use rates that could be paid for non-firm (i.e., power supplied on an "as available" basis) power purchases are based upon energy costs in California. These costs are estimated for each rating period using incremental time-of-use heat rates multiplied by the estimated cost of low sulphur fuel oil. The difficulty of accurately forecasting fuel costs may make the use of actual monthly fuel costs a reasonable alternative to an annual estimate.

An illustrative purchase rate for firm power is presented in the report. Both avoided capacity and avoided energy costs are relevant in estimating purchase rates for firm power. The capacity component of the rate is based on the capacity cost of a gas turbine generating unit. The avoided energy costs are calculated on the basis of the changing incremental heat rates associated with a change in generation capacity.

The report recommends a minimum contract length of one year for firm power. Although the construction of a generation facility typically takes much longer than a year, there are several reasons given for favoring a one year commitment for allowing qualifying facilities to qualify as suppliers of firm power. First, individual qualifying facilities will be quite small in terms of generating capacity. Hence, the failure of one or two such facilities to renew their contracts will have no perceptible effect on the utility's construction plans, and it is unlikely that all such contracts will be cancelled at the same time. The one year contract will tend to encourage the underdeveloped cogeneration market by removing the risk associated with long-term contracts. Finally, since the avoided cost method is based on an estimate of marginal costs for the coming year, the use of a one year contract will match the annual calculation of the utility's cost saving.

Connecticut

The Connecticut Department of Public Utility Control has by interim order approved the purchase rates, referred to in the order as "self-generator rates," proposed by jurisdictional utilities. It was agreed that no capacity costs were currently avoidable, although this circumstance is subject to change.

The avoided system energy cost is based on such factors as fossil fuel cost, power pool savings shares, incremental peak and off-peak heat rates, variable operating and maintenance expense, and avoided line losses. The resulting on-peak and off-peak purchase rates are expressed as a percentage of the utility's average fuel cost each month (e.g., 120% on-peak, 90% off-peak).

If the qualifying facility contractually commits itself to provide firm power, the on- and off-peak percentages used to estimate purchase rates are higher than for non-firm power. When a qualifying facility delivers less than 90% of its contractual commitment, it is paid the lower non-firm power purchase rate.

Idaho

In a final order the Idaho Public Utilities Commission set forth the approach to be used in estimating the avoided costs made possible by purchases from qualifying facilities. Suppliers of non-firm energy are to receive energy payments based on the utility's systemwide avoided energy costs. In addition, the aggregate capacity value of non-firm power from qualifying facilities is to be reflected in a small capacity payment which is proposed by the utility and must be approved by the commission.

The avoided capacity cost associated with the purchase of firm power (i.e., power sold under contractual obligation) is based on the cost per kilowatt of a future base load coal plant. The cost of financing the construction of this plant assumes a prespecified capital structure of 50% debt, 10% preferred stock and 40% common stock. The cost of debt and preferred stock as sources of funds is estimated based on the average costs during the most recent historical test year. Different annual avoided capacity costs per kW are specified for the beginning year of operation of the qualifying facility. Also, the longer the contractual commitment of the qualifying facility to supply power, the greater the annual avoided cost per kW. A table of avoided capacity costs per kW is constructed with various combinations of beginning years of operation and contract lengths.

To qualify for a capacity payment, the cogenerator or small power producer must produce the energy equivalent of operating its generator at full capacity during 75% of the year. The qualifying facility's capacity that justifies avoided capacity payments is found by dividing the qualifying facility's estimated firm total energy production in kilowatt-hours per year by the quantity .75 x 8760 hrs/yr.

The avoided energy cost payments for firm power are based on the operating characteristics of the coal plant used in making the avoided capacity cost calculations. The avoided energy cost payment will be adjusted for fuel cost changes over the life of the contract. In contrast, no adjustment is made to avoided capacity cost payments over the life of the contract.

Iowa

The Iowa State Commerce Commission, in a final order, adopted rules governing payments to qualifying facilities. The commission favors the use of the price of capacity from a power pool as the most accurate means available for estimating avoided capacity costs. Avoided energy costs may also be calculated using power pool rates or the incremental energy costs of the utility itself, any utility with which it is interconnected, or the interstate power grid.

Power provided by qualifying facilities on an "as available" basis is priced based on avoided costs at the time of delivery. Power provided under a legally enforceable obligation is priced according to avoided costs at the time of delivery or at the time the service obligation begins, whichever the qualifying facility chooses.

Kansas

The Kansas State Corporation Commission has issued final orders requiring the filing of tariffs for payments to cogenerators based on the utility system's average embedded costs. These standard rates apply to qualifying facilities with capacity of 100 kW or less.

The energy credit to be paid by a generating utility is found by taking the utility's average cost per kilowatt-hour of producing electricity, including the energy cost adjustment factor, and adjusting it upward to reflect 50% of the utility's normal line loss experience. The adjustment by 50% of the test year annual line loss percentage is to account for the reduced line losses made possible by the distribution of qualifying facilities throughout the system.

The capacity payment per kilowatt-hour to be paid to qualifying facilities by generating utilities is found by multiplying the utility's total production plant cost net of accumulated depreciation by 50% of the authorized rate of return and dividing this by the test year's total annual number of kilowatt-hours of production. Thus, capacity payments to qualifying facilities depend on both the utility's embedded costs and its allowed rate of return.

Non-generating utilities are expected to offer avoided energy cost payments equal to the energy component in the wholesale rates paid by the utilities for purchased power. The capacity credit to be offered by non-generating utilities is equal to one-half of the capacity component of the wholesale rate paid by these utilities.

Massachusetts

The Massachusetts Department of Public Utilities has established an avoided cost calculation method that incorporates the avoided costs associated with a power pooling arrangement. The avoided energy cost is considered the sum of the utilities' avoided fuel cost per kWh, the avoided operating and maintenance costs per kWh, and the power pool savings share. These three components are then adjusted upward using a line loss factor.

The avoided fuel and avoided operating and maintenance expenses for each given rating period are determined using a production cost model which is run three times, at 100%, 90%, and 80% of the expected load during that rating period. At each of these three load levels, the production cost model will yield an estimate of the total fuel, operating, and maintenance expense and the total energy (kWh) produced during the particular rating period. The sum of the fuel and operating and maintenance expenses at 100%, 90%, and 80% of the load expected over the rating period are respectively designated C100, C90, and C80. The total kWh output at each of these three load levels are represented by KWH 100, KWH 90, and KWH 80.

The avoided energy cost for meeting specified rating period's load is given by the larger of the two ratios below:

$$\frac{\text{C100} - \text{C90}}{\text{KWH 100} - \text{KWH 90}}$$

$$\frac{\text{C100} - \text{C80}}{\text{KWH 100} - \text{KWH 80}}$$

These two ratios represent the incremental fuel and operating and maintenance costs per kWh of supplying the last 10% and 20% of the specified load respectively. Under certain conditions the incremental running costs per kWh of generating electricity may be higher for serving the last 20% of the expected load than for serving the last 10% of the predicted load.[1]

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[1]At first glance this may appear to contradict the view that a cost minimizing utility will bring plants on line in order of their greatest operating efficiency. However, since the output of some generating plants may be inflexible, meeting 100% of the expected load at minimum cost may require the use of an older, less efficient, intermediate load unit instead of a new, smaller, more efficient unit that could not produce the required amount of electricity. At 90% of the expected load, the larger capacity of the old intermediate load unit would not be needed and the new, smaller, generating unit could be used instead. Hence, the per kWh cost of serving the last 20% of the expected load could be greater than the per kWh cost of serving the last 10% of the expected load.

The Massachusetts D.P.U. allows smaller utilities (i.e., those with annual retail sales of 500 million kWh or less) to use specific plants or power purchases to estimate incremental avoided energy, operating, and maintenance costs instead of running an elaborate production costing model.

The last component of the avoided energy cost is the avoided cost of a net saving share associated with power pool transactions. The savings share distributes the cost savings made possible through power pooling to member utilities. Both net importing and net exporting utilities receive savings shares for their transaction in the power pool.

The power purchased from cogenerators and small power producers can be used by a utility to increase its exports to or reduce its imports from the power pool or both. A net power exporting utility should find that its saving share receipts are increased due to the additional power supplied by qualifying facilities. A net power importing utility will lose saving share receipts as part of its power imports are replaced by power purchased from qualifying facilities.

The avoided cost per kilowatt-hour associated with saving shares (SS) is calculated using the following formula:

$$SS = [(EX-IM)/(EX+IM)] \times VSS$$

where EX and IM refer to the number of hours of export and import of power to the pool during the rating period, and VSS is the weighted average value of a savings share per kilowatt-hour. If during the rating period a utility exports power for twice as many hours as it imports power, the expression within the brackets equals 1/3, suggesting that a third of any power received from qualifying facilities will result in a net export of power and a savings share income for the utility. If the utility imports power for twice as long as it exports power, the bracketed expression equal -1/3 implying that a third of the power received from qualifying facilities will result in a reduction of net imports and a loss of saving share revenue.

In summary, the avoided energy cost per kWh of energy supplied by qualifying facilities includes the fuel cost per kWh, the operating and maintenance costs per kWh, and the positive or negative saving share avoided cost per kWh, all of which are adjusted to reflect line losses.

In Massachusetts, qualifying facilities with a capacity of 100 kW or less are eligible to receive the standard capacity rate. The avoided annual capacity cost (CC) is considered to be zero, if the utility has excess capacity with regard to the power pool's required reserve margin and if the utility has not purchased or built added capacity since the last capacity rate determination. Otherwise, the utility's avoided capacity cost is assumed to be equal to the power pool's capacity deficiency charge. This capacity deficiency charge is adjusted for line losses at the applicable voltage level and converted to a cents per on-peak kilowatt-hour purchase rate.

For extremely small cogenerator and small power producers (i.e., with capacity of thirty kW or less), the Massachusetts D.P.U. permits the option of running the meter backwards. Qualifying facilities would still pay the minimum fee for electric service. They could not apply a net sale of kilowatt- hours in one billing period to a net purchase of kilowatt-hours in the following period.

Qualifying facilities with a design capacity of more than 100 kW are expected to negotiate the capacity payment and other terms with the utility.

Montana

In a final order, the Public Service Commission of the State of Montana sought to establish standard rates available to all qualifying facilities with the option of contract negotiation encouraged. Of special interest is Montana's provision for partial capacity payments to qualifying facilities. The aggregate capacity credit paid is intended to reflect the fact that while individual qualifying facilities supplying power on an as available basis may not have sufficient reliability to justify a capacity payment, a portion of the power supplied by qualifying facilities collectively is of sufficient reliability to permit a partial capacity payment. Until more is known about the operating characteristics of qualifying facilities, the Montana Commission requires that one-half of the availability factor of a combustion turbine (i.e., 42.5% = .5 x 85%) be used as the proportion of the qualifying facility's production in kW to be paid a full avoided capacity cost credit.

A long-term capacity rate is available to qualifying facilities that agree to a four year or longer performance commitment. The long-term capacity payments would be based upon an 85% availability factor. This is exactly double the capacity credit given for power supplied on an as available basis.

New Jersey

The Board of Public Utilities of New Jersey's Department of Energy has issued final orders regarding the purchase rate that is to be made available to qualifying facilities. This standard rate is made available to qualifying facilities with capacities of one megawatt or less.

The avoided energy cost is estimated as 10% over the PJM power pool's energy billing rate. The 10% premium is intended to reflect the potential cost savings to society at the state and national levels. Facilities between 100 kW and 1 MW in capacity have the option of having their energy sales metered on a time-of-day or an hour-by-hour basis. Qualifying facilities with less than 100 kW capacity are to receive a stable non-time-of-day rate.

New Jersey has authorized two methods to calculate avoided capacity costs. The first method is to calculate avoided capacity costs based on the cost or sales value of capacity of PJM power pool transactions. The second is to use long-run incremental cost analysis. The commission has examined long-run incremental cost studies which show zero avoided capacity costs for the major utilities in the state. However, the commission believes that it would be inappropriate to penalize qualifying facilities because of the excessive oil fired capacity in the state. The commission, therefore, set the price of capacity at that of the value of capacity when the electric utility is at an optimal fuel mix. The commis- sion set the avoided cost of capacity equal to that of a combustion turbine peaking unit. No capacity credits are available if the qualifying facility has a capacity of less than 100 kW.

North Carolina

The state commission has determined that purchase rates paid to qualifying facilities should reflect the utility's avoided costs both in the long run and the short run. The short-run avoided energy costs for peak and off-peak periods may be estimated using a production costing model (e.g., PROMOD) with an allowance made for variable operation and maintenance costs, changes in working capital, and transmission losses. The long-run avoided costs are to be estimated using the capacity costs associated with a peaking unit for contracts covering less than eleven years. For contracts between a utility and qualifying facilities extending over eleven years or more, the capacity cost of a base load unit is deemed appropriate for setting the avoided capacity cost credit. The eleven year cutoff point for the use of base load capacity costs in estimating avoided capacity costs was chosen to reflect the current planning and construction time required for new base load facilities in North Carolina.

Oklahoma

The commission has, through an interim order, instituted an experimental standard purchase rate schedule for small power producers and cogenerators. The commission has reserved its judgment regarding the best method for calculating avoided costs pending further research.

The experimental purchase rates for use by investor-owned electric utilities are on a per kilowatt-hour basis. This standard purchase rate is offered to cogenerators and small power producers with capacity less than or equal to 100 kW. The rate is composed of the sum of three components: a capacity, energy, and fuel adjustment component. The capacity component (CC) is calculated based on the following formula:

$$\frac{AC}{8760 \times \text{capacity utilization}}$$

AC represents the present value of the annual carrying, maintenance, and administration cost per kW of the next generating unit to be brought into service. The term 8760, the number of hours in one year, times the capacity utilization yields an estimate of the total number of kilowatt-hours of usage per year that the utility will derive from each kilowatt of new generation capacity. Dividing AC by the expected number of kilowatt-hours per kW of new generation capacity yields an estimate of avoided capacity costs per kWh of energy purchased from small power producers. This assumes that qualifying facilities' patterns of power delivery, especially at peak, correspond to the utility's load.

The relative efficiency at peak (REP) factor is intended to adjust for the imperfect temporal correlation between utility peak demand and the small producer's peak output. The assumption made in Oklahoma is that REP is equal to unity for photovoltaic and stored water hydropower producers. Wind power is considered less reliable on-peak and has been assigned initially a REP of one-half.

The energy component is based on the cost per kilowatt-hour of energy generated by the next unit of capacity to be brought on line. This avoided energy cost is adjusted upward to reflect avoided line losses. The current monthly fuel adjustment factor is used to update the avoided energy cost calculation on a monthly basis.

The calculation of avoided costs for rural electric distribution cooperatives in Oklahoma is analogous to the preceding calculation for investor owned utilities. However, avoided capacity costs are based on an annual demand charge for wholesale power instead of being based on the present value of the annual carrying, operation, maintenance, and administration costs of the next unit of generation capacity to come on line. The energy component consists of the wholesale energy rate per kWh and an upward adjustment to reflect avoided line losses. The fuel adjustment component reflects the monthly fuel adjustment made by the wholesale supplier of power.

Oregon

In 1981, the Public Utility Commissioner of Oregon set standards for the purchase of power from cogenerators and small power production facilities. Small qualifying facilities with a design capacity of 100 kW or less are to receive payments equal to the higher of the last rate block applicable to either residential or general service customers. Until more data become available on the actual avoided costs attributable to these small qualifying facilities, these standard rates remain in effect. For qualifying facilities with a design capacity greater than 100 kW, power can be sold on a firm or a non-firm basis. Non-firm power producers receive payment for avoided energy costs reflecting the timing of power delivery. Qualifying facilities supplying firm power receive both an avoided energy cost payment and an avoided capacity cost payment.

Each qualifying facility providing firm power has the option, prior to the start of a new contract period, to receive payments based on avoided costs either calculated at the time of delivery or projected to apply over the life of the contract period as calculated at the time the obligation to the supply firm is incurred. Thus, if the owners of a qualifying facility believe that the projected avoided cost escalation is too conservative, they can choose to have their payments adjusted over the life of the contract period to reflect actual inflation of avoided costs. Oregon's capacity payment estimate is that projected avoided capacity payments are based, in part, on the length of the period of firm service agreed to by the qualifying facility with longer firm service commitments receiving higher payments.

Rhode Island

The Public Utilities Commission, in a final order, has established rules governing the calculation of purchase rates for power supplied by cogenerators and small power producers. Standard rates are to be made available to all cogenerators and small power producers, regardless of size. However, the option of a negotiated rate remains open.

The avoided energy cost of a non-generating retail distribution utility is assumed to be equal to the avoided energy cost of the utility's wholesale supplier. A cost minimizing wholesale power producer will have incremental energy costs which are higher than the average energy costs on which wholesale power pricing is based. The commission chose not to use the price at which the retail utility purchases wholesale power as a measure of avoided energy costs. According to the commission, existing institutional and contractual arrangements allow a retail non-generating utility to capture, eventually, the incremental energy cost saving associated with the wholesale supplier's reduced energy sales. This implies that the current wholesale power rate will not fully reflect the avoided energy cost made possible by purchases from qualifying facilities and that the avoided energy cost of the wholesale producer should be used instead.

The commission specified a method of calculation to be used in estimating the energy costs avoided by a self-generating electric utility (or a wholesale supplier). First, the utility's load is assumed to be reduced by one percent during every hour of the last twelve months. The average fuel cost of generating the reduced load is calculated for peak, off-peak, and total hours (adjusted for seasonal peaks). Then the average fuel costs of generating the decremental load is calculated for the peak, off-peak, and total hours. The one percent decrement in load is intended to reflect roughly the potential annual output from qualifying facilities. The on-peak, off-peak, and average ratios of the average fuel cost per kWh of the decremental load, to the average fuel cost per kWh of serving the remaining load, are multiplied by current, average fuel costs for peak, off-peak, and average hours to yield an avoided energy cost per kWh for the peak, off-peak, and average rating periods. Qualifying facilities with time-of-use meters will be paid their avoided energy cost based on their output during peak and off-peak periods. For qualifying facilities without time-of-use metering, the average avoided energy cost, seasonally adjusted, will be paid.

The costs or avoided costs associated with line losses are to be estimated by the purchasing utility for each individual qualifying facility. The line loss costs or avoided costs are expected to vary significantly based upon the qualifying facility's geographic location and voltage level of output. The specific line loss costs or avoided costs of each qualifying facility are then reflected in the purchase rate for that facility.

Producing utilities in Rhode Island were found to have excess capacity and thus avoided capacity costs were considered to be zero. In the case of a non-generating distribution utility, it is expected that the retail utility will not avoid or incur any avoided capacity costs through its qualifying facility purchases.

Texas

The Public Utility Commission of Texas sponsored a 1980 task force report on cogeneration. The task force included representatives from over fifty industrial companies and utilities. The report recommends that cogeneration agreements be reached through good faith negotiations, subject to commission arbitration, should a dispute arise. In addition, the report recommends that cogenerators and small power producers offering non-firm energy be paid on the basis of avoided energy costs. The utility would be expected to use an economic dispatch model to determine avoided energy costs, taking into account both the timing and amount of power furnished.

The report recommends the differential revenue requirements method as a guide for the negotiation of actual payments for firm power supplied by qualifying facilities. This method would estimate both avoided energy and capacity costs together. Detailed load and financial forecasts would be used in a generation expansion model and a financial planning model to estimate the utility's required revenue,[2] both with and without the output of qualifying facilities. The difference between these revenue requirements would be an estimate of the utility's total avoided costs associated with purchases from qualifying facilities.

The task force report also addresses the question of avoided costs for sales to a non-generating utility. Such utilities typically purchase wholesale power under long-term contracts which provide for capacity charges. Since a non-generating utility will not be able to avoid the capacity charges associated with unused capacity under the existing contract, the task force reasons that only the energy component of the wholesale power rate can be avoided by the non-generating utility. Hence, the wholesale rate paid by a non-generating utility would have to be adjusted to remove capacity charges before it could be considered an avoided cost estimate. When capacity charges can be avoided by non-generating utilities, they should be included in the avoided cost paid to qualifying facilities.

Utah

The Public Service Commission of Utah, through an interim order, has implemented rules governing payments to cogenerators and small power producers. In the case of Utah Power, avoided costs of energy and capacity were based on the costs associated with a specific facility. The avoided energy costs alone were estimated using the average cost of energy purchased by Utah Power and may be used in situations where a capacity credit is inappropriate.

A restriction recommended by Utah Power and upheld in lieu of further investigation by the commission is that a qualifying facility must have a load factor which is equal to or higher than the average load factor of the

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[2]Required revenue refers to the revenue needed to cover the utility's variable costs and to provide the allowed rate of return on the rate base investment.

utility to qualify for avoided capacity cost payments. Purchase rates for cogenerators and small power producers with more than 1,000 kW of capacity or hydro qualifying facilities of 100 kW or more are to be negotiated with the utility.

Virginia

The State Corporation Commission of Virginia on June 18, 1981, issued a final order implementing the FERC rules concerning cogeneration and small power production for the Old Dominion Power Company. The commission found that avoided costs could be estimated using the cost of wholesale power updated to reflect any permanent change. Negotiated rates subject to commission arbitration were deemed appropriate for qualifying facilities with capacities greater than 100 kW.

The utility is permitted to collect interest on interconnection costs that are paid by the qualifying facility over a period of time. The interest rate charged by the utility is limited to no more than the interest on the utility's most recent issue of long-term debt.

Summary

The avoided cost approaches of the sixteen states reviewed in this chapter give an indication of the diversity of approaches in applying avoided cost concepts to specific circumstances. In some states the application of avoided cost methods must reflect special local conditions, such as excess capacity, or the extensive use of power pooling arrangements. Practical considerations often require departures from theoretically ideal avoided cost estimates, such as when the special metering needed to adminis- ter a sophisticated avoided cost rate structure proves to be prohibitively expensive for small qualifying facilities. While this survey does not indicate a consensus of opinion on the best practical approach for estimating avoided costs, it demonstrates the widespread interest and originality of state commissions in adapting the concept of avoided cost to the real world.

CHAPTER 3

AN IDEALIZED METHOD FOR QUANTIFYING AVOIDED COSTS

In this chapter, an idealized method for computing avoided costs is presented. The avoided costs computed by this method are based on the concept of marginal cost and a theory of peak-load pricing. This method relies heavily on a computer simulation of the utility's planning for future capacity expansion and a simulation of the economic dispatch of the system over the planning horizon. This reliance on computer simulation, however, does not detract from the general usefulness of this idealized method. The goal is to provide a sample model. Many computer simulations of the planning process yield formulas that can be used in computing approximately the costs of marginal capacity without the aid of a computer. It does require, however, the costs associated with two expansion plans be made available. The marginal running costs are not easily generalized, yet may be readily obtainable from the utility. In cases where a public utility commission lacks access to computer facilities or the data necessary to perform the calculations, the idealized method can provide a general framework within which to evaluate proposed methods of quantifying avoided costs.

In the first section of this chapter, the definition of avoided cost is discussed and a marginal cost conceptualization of avoided costs is adopted for the idealized method. The solution to a peak-load pricing model is presented in the second section. These theoretical results provide guidelines for developing the formulas for measuring avoided costs. To this end, the interpretation of the solution is designed to begin bridging the gap between theory and its application. The third section presents some of the basic issues of applying marginal cost theory and a possible approach to resolving these issues. In the fourth section, the distinction between firm and non-firm commitments of capacity is discussed. A method for computing the cost of avoided capacity is presented in the fifth section. The sixth section contains a method for calculating the avoided running cost. A method for allocating the cost of avoided capacity to the hours of the year is presented in the seventh section.

Defining Avoided Costs

The Federal Energy Regulatory Commission's (FERC) rules regarding rates for the purchase of power from small power producers and cogenerators require that rates be based on the utility's avoided costs. The FERC defines avoided costs as 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.[1] Incremental and avoided costs are measurable costs based on the theoretical concept of marginal costs. Strictly speaking, marginal cost refers to the additional cost of producing a single, infinitesimally small additional unit. Incremental and avoided costs are used to refer to the average additional costs of a finite and possibly large change in production or sales.[2] These latter ideas of incremental and avoided costs are approximations of the former marginal costs.

Having defined avoided costs as a marginal cost, however, does not necessarily help one develop rates for power purchased from qualifying facilities. One could think of two cost of service studies, each of which quantifies the cost of service the utility experiences over its planning horizon. The difference between these two costs is that for one of the studies some of the electricity is supplied by small power producers and cogenerators. The remaining cost of service study yields that cost the utility would experience if it supplied all of the electrical needs of its customers. The change in total costs between these two circumstances is a

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[1]See CRF Part 292.101(b)(6), 45 FR 12234.

[2]See Alfred E. Kahn, The Economics of Regulation: Principles and Institutions, 2 Vols., New York, John Wiley and Sons, Inc., 1970, Vol. 1, p. 66.

lump sum for a given block of avoided output. This approach is called here a cost-savings approach to avoided costs. With this approach, unfortunately, translating this avoided cost into rates is more difficult.

The marginal cost approach to avoided costs calculates directly a set of marginal costs per unit of avoided output and capacity for each hour of the year. These marginal costs are easily translated into prices for the power purchased from qualifying facilities. This price per kilowatt-hour (kWh) is based on a measure of the cost of avoided capacity per kilowatt of avoided capacity and the avoided running cost. While this approach is much easier to implement than the former approach, it may suffer a serious shortcoming. By pricing purchases from qualifying facilities in this way, revenue requirements may not be left unchanged as they would with the cost-savings approach.

The idealized method for computing avoided costs presented in this chapter is based on the marginal cost approach to avoided costs. In chapter 4, it is demonstrated that this approach, in all likelihood, will increase the revenue requirement. However, the pricing prescriptions of the marginal cost approach provide guidelines for implementing the cost-saving approach to avoided costs. The cost-saving approach is viewed as having less of an adverse impact on the utility's customers because it leaves the revenue requirement unchanged.

An Idealized Hourly Marginal Cost Model

In this section, an ideal social welfare model is discussed in which consumer prices could conceivably vary hour by hour. A formal description of the model is in appendix C. In reality, consumer prices do not change hourly. Nonetheless, this idealized model provides some practical insights about ways to compute the utility's marginal cost even when there are only one to two pricing periods in the year. The utility's marginal cost, in turn, is important in developing a measure of avoided cost.

Optimal Prices

Social welfare, as traditionally defined as the sum of consumer's and producer's surplus, is maximized when consumers are charged a single price equal to marginal cost for each pricing period.[3] In the context of a system capable of hour-by-hour metering, these optimal prices are given by

$$P_t = \frac{\partial C_t(q_t, K)}{\partial q_t} + \gamma_t \quad \text{on-peak} \tag{3.1}$$

$$P_t = \frac{\partial C_t(q_t, K)}{\partial q_t} \quad \text{off-peak} \tag{3.2}$$

where the terms are described in appendix C. Briefly, P_t is price charged in time period t, C_t is valuable cost that depends on energy, q_t, and capacity, K, and γ_t is a rationing cost. The first term on the right hand side of equations 3.1 and 3.2 is the marginal running cost experienced in period t. Thus, by equation 3.2, the off-peak period's price is based only on the marginal running cost. These costs are the change in the variable costs of operation for period t attributable to a change in output during that period.

The on-peak period's price is based on marginal running cost plus a rationing cost given by γ_t. A rationing cost rations scarce capacity during periods of high demand by increasing until the quantity demanded is equated to available capacity. Thus, the on-peak price is based on a cost consisting of an energy component and a capacity component.

The capacity portion of the marginal cost incurred during the on-peak period is related to the level of capacity installed. The optimal level of

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[3]Alternatively, the same social welfare maximum can be achieved by perfect price discrimination. In the context of this report, an example would be each qualifying facility receiving its own marginal cost from the utility. Allowing the utility to discriminate in this fashion essentially results in the utility capturing the excess profits, if any, of the qualifying facilities. This is clearly not a scheme that bases price on the utility's avoided cost, and consequently is not analyzed here. Furthermore, if implemented, this scheme would require marginal cost of service studies to be submitted to a public utility commission by the qualifying facilities.

capacity is installed when

$$\sum_{t}^{n} \gamma_t = \sum_{t}^{n} \frac{\partial C_t(q_t, K)}{\partial K} + \frac{\partial \overline{q}(K)}{\partial K} \tag{3.3}$$

The condition in equation 3.3 states that the sum of the rationing costs for all time periods equals the cost of marginal capacity. This marginal cost consists of two elements. The first expression on the right hand side of equation 3.3 is the change in running costs attributable to changing the capacity of the system. The second expression is the change in the fixed costs attributable to changing capacity. When the rationing costs (γ_t) sum to the cost of marginal capacity, the utility has installed the level of capacity necessary to maximize welfare over the entire demand cycle when charging prices given by equations 3.1 and 3.2.

The price for each time period is equal to the marginal running cost plus a capacity rationing cost. This rationing cost is a positive amount when the quantity demanded is equal to capacity and zero when the quantity demanded is less than capacity. The sum of the rationing costs over the entire demand cycle yields the costs of marginal capacity. This capacity cost is equal to the change in the fixed cost attributable to varying capacity plus the sum of changes in the running costs for each time period attributable to adjusted capacity. In practical terms, this means a demand of 1 kW for 8760 hours should be priced so as to recover the annual addition to the cost of capacity per unit of added capacity plus the change in running costs per unit of added capacity plus the marginal running costs associated with the 8760 kWh produced.

An Interpretation

The demand served by the utility in the model is assumed to be a multiple-period demand cycle. This could be an annual demand cycle divided into the hours of the year or some appropriate grouping of the hours of the year. In these circumstances, avoided costs would be calculated on an annual and hourly basis.

The marginal running costs are computed for all hours of the year whether they are on-peak or off-peak hours. The marginal running costs are the changes in the variable costs of operation attributable to varying the hourly output of the generating system. A major component of the marginal running cost is the cost of fuel associated with one more or one less kWh. In addition, changes in the operation and maintenance expenses related to the hourly output of the system must be quantified. These marginal running costs vary over the demand cycle and their variation should be quantified to the extent feasible and practicable.

The cost of marginal capacity is computed on an annual basis and assigned to the on-peak hours of the year. This capacity cost is the sum of two costs. The first component of capacity cost is the change in capacity which affects the system's running costs. Changes in fuel costs and changes in operation and maintenance expenses attributable to the cost of marginal capacity is the change in fixed costs attributable to varying capacity. Fixed costs are defined as costs that do not vary with output. Usually, one would consider the costs of structures, equipment, and land as fixed costs. Thus, the construction cost of new plants entering service is an example of a change in fixed costs attributable to changes in capacity. By adding the change in running costs attributable to changing capacity, one obtains the cost of marginal capacity.

The foregoing model makes no mention of the avoided costs of distribution or transmission plant. This is because the utility's demand-related and energy-related transmission costs may be higher or lower for power purchased from a cogenerator or small power producer. Factors that might affect whether these charges are higher or lower include the geographic location of the qualifying facility and its proximity to the utility's high-demand market areas, and the voltage level of the qualifying facility's output. The utility is likely to incur additional distribution costs for qualifying facilities because of the additional equipment that would be necessary to have the qualifying facility generate so as to ensure system safety and reliability of the interconnected operations. These additional interconnection costs can be handled separately from the rates for purchase from the qualifying facility. If there are additional transmissions cost or savings related to purchases from the qualifying facility, these can be netted out or added to the interconnection costs on a case-by-case basis.

The cost of marginal capacity is best expressed on an annual basis and as the present value of changes over the utility's planning horizon. These annual costs of marginal capacity can be used directly in ratemaking or assigned to the hours of the year if a peak-load pricing tariff is desired. In this latter case, the assignment factor must reflect the probability that the quantity demanded during any hour will exceed the available capacity.

Some Basic Issues of Applying Marginal Cost Theory

When the theory of marginal costs is put to practical application, some basic issues concerning the kinds of information necessary to quantify marginal costs are raised. The nature of the problem presented by the purchase of power from small power producers and cogenerators greatly simplifies the resolution of these issues. Provisions in the contract a utility will negotiate with a qualifying facility provide information useful in calculating the costs avoided by the purchase of power. Beyond this source, the theoretical results presented in the last section provide help in identifying the necessary information.

Several issues can be raised in the regulatory arena when attempting to quantify the marginal costs of production. The first set of issues involves the specifications of two parameters of marginal cost. The first parameter is the time period over which costs are measured. Since the theoretical model is a long-run model, the utility's planning horizon would seem to approximate this guideline. The second parameter is closely related to the first: the incremental block of output over which costs are to be measured. Estimates of the type and size of all capacity commitments that potentially can be made to enable regulators and the utility to best approximate this block of output. Finally, one can confront issues involving the treatment of joint costs. Capacity installed to serve the peak is available to serve any other time period. These joint costs should be assigned to the time periods in which they are incurred. The probability calculations underlying the planning for system reliability provide a strong background for developing an allocation factor for this purpose.

In determining avoided output for the avoided cost calculation, it is useful to think in terms of all potential contracts the utility might negotiate. These include contracts with both large (more than 100 kW) and small (100 kW or less) qualifying facilities. Provisions in the contract between a utility and qualifying facility provide the information necessary to begin calculating avoided costs. This contract contains several conditions of supply on which both the utility and qualifying facilities have agreed. These contract provisions are used to adjust the normalized load curve the utility expects over its planning horizon.[4] The relevant provisions are the following:

1. The qualifying facility's net dependable capacity available for purchase during specified time periods (ideally, availability on an hourly basis should be specified for typical weekdays and weekends with scheduled maintenance outages also specified);
2. The hours or time periods of the year in which capacity is available on a firm basis and a non-firm basis;
3. The term of the contract in weeks, months, or years;
4. The availability of the qualifying facility's unit during a utility system's emergency.

Contract provisions pertaining to interconnection costs and the sale of power by the utility to the qualifying facility are not relevant to the calculation of avoided costs under this approach, and are kept conceptually and computationally separate here. These four items of information for all qualifying facilities with which the utility has purchase agreements are used to adjust the normalized load curve expected over the planning horizon. This adjusted load curve is used to develop a new capacity expansion plan and operating strategy.

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[4]The normalized load curve refers to a load curve reflecting average temperatures.

Firm Versus Non-firm Commitments of Capacity

The distinction between a firm commitment of capacity and a non-firm commitment is an important one with a substantive impact on the utility's planning process and operating strategy. A firm commitment of capacity by a qualifying facility is a guarantee that the level of capacity and power output stated in the contract will be available to the utility. It is "as if" the utility purchased the capacity. A non-firm commitment, on the other hand, is an "as available" purchase of power from a qualifying facility. In this case, there is no guarantee that power will be available at any hour. The avoided costs in this latter case are different from that of a firm commitment of capacity.

Firm Capacity

A firm commitment of capacity by a qualifying facility has a predictable effect on the capacity expansion plan. The four items of information that are obtainable from the contracts a utility has signed with qualifying facilities enable the utility to adjust its normalized load curve for planning purposes. The net dependable capacity each and every qualifying facility makes available to the utility during each hour or time period of the planning horizon is subtracted from the utility's predicted normalized load during that hour or period. This adjusted load curve is used in planning capacity expansion.

The length of time for which firm commitments of capacity are made affects the relative growth rates of the normalized load expected over the planning horizon. Short-term contracts of one or two years may merely delay the expansion of the generating system. Intermediate-term or long-term contracts, on the other hand, may alter the optimal expansion plan or lead to the cancellation of planned expansion. The cost of avoided capacity in each of these cases may vary substantially because of the effects on the timing of capacity expansion.

The availability of a qualifying facility's unit during a system emergency can affect a utility's planning for reserve capacity to assure the system's reliability. As a result, capacity that otherwise would be installed by the utility to assure a given level of reliability may be postponed, altered, or cancelled. The capacity from qualifying facilities can be added to system reserves for each hour or time period according to the probability of a system emergency occurring. This practice may increase the avoided cost of capacity attributable to the qualifying facility's availability during a system emergency.

Non-firm Capacity

Since a utility is required to purchase power from qualifying facilities, it must factor the projected availability of non-firm commitments of capacity into its planning process. If a utility were to ignore non-firm purchases in planning capacity expansion, it might fail to minimize the costs of service during periods in which non-firm purchases are made. This failure to minimize costs occurs because the utility would be carrying excess capacity. The effect of non-firm commitments of capacity is to introduce an additional stochastic variable in the utility's supply. This stochastic variable has a non-negative expected value and variance. As a result, the expected normalized generation for each hour of the year is reduced by the expected value of these purchases. Thus, the load curve used in planning capacity is altered,[5] which in turn can alter the optimal capacity expansion program.

Whether quantifying or predicting the availability of non-firm capacity is worth the effort primarily depends on the operating information available to the utility. Initially, operating experience from which to draw data to calculate availability may not exist. This may be particularly true for small power producers using wind and solar sources.

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[5]Of course, the hourly load (demand) is not altered, but the generation (supply) is reduced by the available capacity from qualifying facilities. For simplicity, the normalized load curve is said to be reduced. This expression is used from here on.

However, as operating experience and data on metered output from these sources become available, as well as data from other cogenerators and small power producers, the utility can better integrate non-firm commitments of capacity into its planning. The upshot of quantifying the availability of non-firm commitments of capacity may be the inclusion of a cost of avoided capacity in the rates paid for power purchased from qualifying facilities making these non-firm commitments.

Conclusion: A Word of Caution

Both firm and non-firm commitments of capacity by small power producers and cogenerators reduce the expected growth rate of the normalized load that the utility faces during its planning horizon. Use of this adjusted load curve in capacity planning can change the timing of capacity expansion and the characteristics of units to be added. Firm and non-firm commit- ments, however, differ substantially in their stochastic characteristics. Thus, their impact on capacity planning and the operating strategy, when taken separately, can lead to different costs of avoided capacity for each type of commitment.

A Method for Calculating the Avoided Cost of Capacity

The idealized method for computing the cost of avoided capacity is rooted in the planning process. Computer simulations of capacity expansion planning often use dynamic programming to choose the least-cost capacity expansion and operating strategy. The mathematical expression for this least-cost choice along with two expansion plans provides the basis for the calculation of the cost of avoided capacity. The first expansion plan designates the cost-minimizing additions to generating capacity given the expected normalized load curve without purchases of power from qualifying facilities. The second expansion plan designates the cost-minimizing additions with the purchase of power from qualifying facilities. The annualized difference between the present values of the costs of these two plans is the cost of avoided capacity.

The outcome of the first run of the computer simulation of capacity planning is a set of costs associated with the optimal additions to generating capacity, and is expressed as

$$\sum_{t}^{n}(C_t - R_t + O_t) \qquad (3.4)$$

where t is an index for the n years in the utility's planning horizon; C_t is the total cost for units that enter service in year t; R_t is the cost of units entering service in year t that is not recovered over the planning horizon; and O_t is the total running cost in year t for all units. Any other expansion plan would result in a higher total cost of generation over the planning horizon. This expansion plan is the base case; it is the cost that would be incurred without the purchase of power from qualifying facilities.

Before continuing, possible formulas underlying equation 3.4 are presented. The total costs of units entering service in year t is given by

$$C_t = \sum_{f} \frac{P_f^k K_f N_{ft} \quad (1 + p^f)^t}{(1 + i)^t} \qquad (3.5)$$

where f - an index of the fuel type of capacity

P_f^K - the current cost for a MW of capacity of type f, including interest during construction

K_f - the capacity in MW of the unit of type f

N_{ft} - the number of units of type f that are added in year t

p^f - the assumed average rate of inflation for construction costs for units of type f over the utility's planning horizon (base year is t = 0)

i - the social discount rate for present-value calculations (base year is t = 0)

The cost of units entering service in year t that is not recovered over the planning horizon is often referred to as a capacity credit for a unit. This is computed as the present value of the accumulated straight-line depreciation plus salvage value that has yet to be recovered at the end of the utility's planning horizon. It is expressed as

$$R_t = \sum_f \left[1 - \frac{(n-t)}{L_f}\right] \frac{P_f K_f N_{ft} (1+P^f)^t}{(1+i)^{(n-t)}} \qquad (3.6)$$

where L_f is the economic life of units of type f and the expression in brackets is the proportion of the unit's economic life remaining at the end of the utility's planning horizon.

The operating costs are calculated as the present value of future fuel and operating and maintenance expenses for all units in operation in a given year. Thus, these are the operating costs for existing units and additions to the system. These costs can be expressed as

$$O_t = \sum_j^{N^t} \frac{P_j^h Q_j (1+p^h)^t + P_j^m Q_j (1+p^m)^t}{(1+i)^t} \qquad (3.7)$$

where j - an index of the N^t units on the utility's system. This includes units existing in year t and those added in year t.

P_j^h - the weighted-average cost of fuel h per MWh for the j^{th} unit on the system in year t.

Q_j - the output of the j^{th} unit in year t.

p^h - the rate of inflation for fuel of type h.

P_j^m - the average cost of operation and maintenance per MWh for the j^{th} unit on the system in year t.

p^m - the rate of inflation for operation and maintenance expenses for the j^{th} unit.

Equations 3.5, 3.6, and 3.7 are suggestive of the formulas underlying the costs of the optimal expansion plan given in equation 3.4. Other formulations are possible.[6] Each should quantify the total costs of construction less the capacity credit for units to be added to the generating system over the planning horizon plus the total fuel and operating and maintenance expenses incurred in serving the projected load over the planning horizon. The optimal expansion plan minimizes these costs.

The first run of the computer simulation of capacity planning provides the base case for the calculation of the avoided cost. The second run of the capacity expansion model determines the minimum-cost expansion plan given that the utility is purchasing power from qualifying facilities. As previously noted, an assumed amount of power purchased from qualifying facilities is used to adjust the normalized load expected over the planning horizon. The cost of the optimal plan given the purchase of power is expressed as

$$\sum_{t}^{n}(C_t' - R_t' + O_t') \tag{3.8}$$

where the ' denotes the same cost results in the case of purchase from qualifying facilities. Given the expected load curve, any other expansion plan would result in higher total costs over the planning horizon.

Equations 3.4 and 3.8 are the basis for calculating the costs of avoided capacity for the utility's planning horizon. If K_t is the capacity added in year t for the base case and K_t' is the capacity added in year t when purchases are made from qualifying facilities, the cost of

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[6]An alternative formulation for the calculation of the fuel costs would specify a number of points on a heat rate curve, the amount of output generated at each point, and the cost of a Btu of the fuel.

avoided capacity over the planning horizon can be expressed as

$$ACC = \frac{\sum_{t}^{n} (C_t - C_t') - (R_t - R_t') + (O_t - O_t')}{\sum_{t}^{n} (K_t - K_t')} \tag{3.9}$$

where ACC is the cost of avoided capacity. The first parenthetical expression in the denominator on the right-hand side of the equation is the present value of the change in the total cost of construction for the entire planning horizon. The second parenthetical expression is the present value of the change in the capacity credit for the planning horizon. These first two parenthetical expressions constitute the change in fixed costs incurred over the planning horizon attributable to varying capacity. The third parenthetical expression is the present value of the change in running costs for the entire planning horizon. The expression in the denominator is the capacity the utility avoids installing over the entire planning horizon.

The reoptimization of the utility's system and adjustments to construction projects will change the utility's income and property tax liability. This change in the tax liability is a capacity-related cost and properly should be included in the cost of avoided capacity. The annual tax liability per unit of capacity the utility avoids installing over the planning horizon can be expressed as

$$ATX = \frac{\dfrac{\alpha tx^{I} \sum_{t} (C_t - C_t') r}{(1 - tx^{I})} + tx^{p} \sum (C_t - C_t')}{\sum_{t} (K_t - K_t')} \tag{3.10}$$

where ATX - the avoided taxes per unit of avoided capacity.

α - the portion of the utility's net operating revenues paid to holders of preferred and common stock, including retained earnings.[7]

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[7]The utility's net operating revenues is defined as that money the utility is allowed for payment of interest and dividends and for retained earnings.

tx^I - the combined federal, state, and local income tax rate.

tx^P - the property tax rate.

This formulation of the avoided income tax assumes the use of straight-line depreciation in the determination of the tax expense for the revenue requirement. If flow-through of the tax benefits of accelerated depreciation is used the calculation for the avoided tax is different than that presented here. The avoided tax liability is an annual cost added to the annual cost of avoided capacity.

The costs of avoided capacity should be stated on an annual basis. These costs consist of the annual costs necessary to pay interest and dividends on securities issued to construct additional capacity plus the straight-line depreciation charge associated with depreciating the cost of avoided capacity over the planning horizon plus the avoided taxes. The average annual cost of avoided capacity is

$$AAC = \left[ACC + \left(\frac{\sum_{t}^{n} (R_t - R_t')}{\sum_{t}^{n} (K_t - K_t')} \right) \right] r + \frac{ACC}{n} + ATX \tag{3.11}$$

where AAC is the annual cost of avoided capacity and r is the weighted-average cost of capital or the utility's allowed rate of return. The change in the capacity credit is added back out because the utility must pay a return on the entire investment in service during the planning horizon. Thus, the return on this capacity credit that is avoided must be included in the annual cost of avoided capacity. The last term on the right hand side is the straight-line depreciation of the cost of avoided capacity over the n years of the planning horizon. The annual cost of avoided capacity (ACC) is the approximation to the theoretical cost of marginal capacity (equation 3.3) to be used in ratemaking.

A Method for Calculating The Marginal Running Costs

In a previous section, marginal running costs were defined as the changes in the variable costs of operation attributable to varying the hourly output of the generating system. This cost is used in the day-to-day operation of a generating system. The system lambda (λ_{it}) is the cost of the next MWh to be produced and delivered to the busbar. By dispatch- ing units according to the lowest system lambda, a utility or power pool can minimize the costs of generation. In planning its capacity expansion and operating strategy, a utility or pool must estimate hourly system lambdas for each hour of the planning horizon or typical days for each year in the planning horizon. Production cost computer simulation can be used to generate these estimates.

The avoided cost in the context of marginal running cost is best approximated by the set of system lambdas that would have occurred but for the purchase of power from qualifying facilities. This means the system would be dispatched to meet the load curve for the base case, that is, unadjusted for purchase of power from qualifying facilities. In doing this, assumptions concerning an optimal expansion plan and operating strategy that will not be actualized must be made. These assumptions merit careful examination.

First, units that might have been constructed but were not or had construction delayed must be assumed to be on line and operable. The availability of these units and the characteristics of their heat rate curve must be integrated into the estimates for the hourly system lambdas. A second related assumption concerns the cost of fuel delivered to these hypothetical plants. The cost of fuel, the unit's heat rate curve, and the unit's equivalent availability are the major determinants of the hourly system lambdas. Realistic assumptions based on highly probable operating scenarios or past experience are of the utmost importance.

The inability to verify these assumptions based on later operating experience is a problem. Using future test year data raises some of the issues involved in basing rates on projected costs, but it allows verification at a later date and adjustments to the costs based on actual operating data. The avoided costs estimated for capacity and operation are truly avoided and the input data for the cost estimates need to be as accurate as possible.

In summary, the marginal running costs are estimates of the hourly system lambdas that would be incurred but for the purchase of power from qualifying facilities. These estimates include the costs of dispatching generating units which are either delayed or cancelled due to the purchase of power from qualifying facilities. The estimates of hourly system lambdas can be used in conjunction with the costs of avoided capacity to develop rates for power purchased from small power producers and cogenerators.

Allocating the Joint Capacity Costs to the Hours of the Year

Capacity installed to serve any given time period is available to serve all other time periods. It is a joint cost of production. The costs of avoided capacity were calculated for the entire planning horizon and then converted to an average annual cost. In this section, an allocation factor for assigning the annual cost of avoided capacity to the hours of the year is presented. It assigns capacity costs to each hour when there exists a positive probability of the quantity demanded exceeding the capacity of the system.

The loss-of-load probability has been used for this purpose in other marginal cost applications and is suitable in these circumstances. If LOLP is the loss-of-load probability for hour i, the allocation factor for hour i (A_i) is given by

$$A_i = \frac{LOLP_i}{\sum_i^{8760} LOLP_i} \tag{3.12}$$

where

$$\sum_{i}^{8760} A_i = 1 \qquad (3.13)$$

The cost of avoided capacity is assigned to the hours of the year as

$$AAC_i = A_i(AAC) \qquad (3.14)$$

where AAC_i is the cost of avoided capacity allocated to hour i.

The loss-of-load probabilities used in this allocation factor are the set of probabilities associated with the load curve adjusted for purchases of power from qualifying facilities. By using this set of loss-of-load probabilities, the costs of avoided capacity are assigned to the hours of the year during which they would be incurred but for the purchase of power from qualifying facilities. The higher cost during these hours is a cost justification for higher rates for the purchase of power during these hours. The higher rates provide incentive to existing and potential qualifying facilities to make their capacity available during these hours.

Summary of an Idealized Method for Calculating Avoided Costs

In this chapter, an idealized method for calculating the avoided costs resulting from the purchase of power from small power producers and cogenerators has been presented. The design of this method was based on and sought to approximate the theoretical model presented in appendix C. To this end, the annual cost of avoided capacity is an average over the future years of the changes in the annual fixed costs of providing service per unit of avoided capacity plus the changes in annual operating costs per unit of avoided capacity both of which are attributable to the purchase of power from qualifying facilities. This annual cost of avoided capacity is allocated to the hours of the year according to the loss-of-load probability experienced when the purchase of power from qualifying facilities is made. In doing this, the costs of avoided capacity are assigned to the hours of the year when there exists a positive probability that the quantity demanded will exceed capacity. Finally, the marginal running costs for each hour of the year are approximated by the set of system lambdas that would have been incurred but for the purchase of power from qualifying facilities. Thus, the avoided costs for on-peak hours are the allocated costs of avoided capacity plus the system lambda for the base case. The avoided cost for off-peak hours is the system lambda for the base case. These hourly costs provide the cost basis for formulating rates for the purchase of power from qualifying facilities.

CHAPTER 4

RATE STRUCTURES, REVENUE REQUIREMENTS, AND AVOIDED COSTS

Ratemaking for purchases of power from qualifying facilities raises a potpourri of issues. The idealized method presented in the previous chapter quantifies the average annual cost of avoided capacity which is distributed over the hours of the year and added to the avoided running cost which is based on the hourly system lambdas. These hourly costs could be averaged for typical days to generate an on-peak, off-peak pricing system for the purchase of power from qualifying facilities. Accordingly, the resulting pricing system could be said to be allocative efficient and welfare maximizing. This system of prices, however, may be considered inadequate for a number of reasons. First, even if regulatory authorities accept the criteria of allocative efficiency and welfare maximization, there may be several cost-based justifications for deviating from average hourly avoided costs and the resulting system of prices. Contract provisions for firm versus non-firm commitments of capacity, the duration of the contract, and the availability of capacity during a system emergency can be justifications for differential pricing of purchased power based on variations on the avoided cost of service. Beyond cost justifications, regulatory authorities could deem the criteria of allocative efficiency and welfare maximization as incomplete. While still basing prices on the marginal cost approach to avoided costs, regulatory authorities might want to ensure that the revenue requirement does not increase so that goals involving equity and distributive justice may be achieved.

In the first section of this chapter, cost-based deviations from the average annual cost of avoided capacity are discussed, and an algorithm for their computation is presented. In the second section, the effect on the revenue requirement of rates based on the marginal cost approach to avoided cost is examined. The cost-saving approach is developed and is suggested as a method for calculating avoided costs that will leave the revenue requirement unchanged.

Cost-Based Deviations from the Average Annual Cost of Avoided Capacity

In this section, the idealized method for computing the cost of avoided capacity is altered to capture variations in this cost that are attributable to the availability of the qualifying facility's capacity to the utility. The idealized method presented in the previous chapter quantifies the annual cost of avoided capacity for the entire planning horizon. This practice of averaging capacity related costs over several years of capacity increments is a widely accepted practice for marginal cost calculations. When one turns attention to formulating rates for the purchase of power from qualifying facilities, the development of a rate structure that signals to qualifying facilities the importance of their availability to the utility seems a desirable goal.

A qualifying facility can commit capacity to the utility on a firm or non-firm basis. A non-firm commitment of capacity is the lowest level of commitment. A firm commitment of capacity can vary with the degree of commitment made to the utility. The term of the contract in years has important effects on the utility's planning for capacity expansion. Rates for power purchased from qualifying facilities could signal to potential and existing qualifying facilities the term of commitment that has the greatest cost savings. Finally, a qualifying facility can commit its capacity during a utility's system emergency. This commitment reduces the capacity the utility must install to meet reliability standards. This availability has an effect on cost of avoided capacity different from that of a firm commitment of capacity regardless of its term. For each type of commitment, a rate structure reflecting legitimate and quantifiable differences in the cost of avoided capacity might be highly desirable.

In doing this, the utility can signal to potential and existing qualifying facilities the types of commitments that yield the greatest cost savings.

Non-firm Commitments of Capacity And the Cost of Avoided Capacity

In the previous chapter, purchases from qualifying facilities that do not or can not make firm commitments of capacity were stated to have an effect on the utility's planning for capacity expansion. In this subsection, the practice of including a cost of avoided capacity in the rate paid to qualifying facilities making non-firm commitments is questioned. Although not totally grounded in a cost of service rationale, the predictability of the availability of non-firm capacity can change the treatment of this capacity for planning purposes.

The effect that non-firm commitments of capacity have on the planning process is an aggregate effect. The time diversity of the availability of non-firm capacity reduces the uncertainty surrounding the availability of any single qualifying facility's capacity. A non-firm commitment of capacity leaves contractual control of the capacity in the hands of the qualifying facility. Thus, the coincident availability of non-firm capacity may not be a sufficient justification for the inclusion of the avoided cost of capacity in the rate paid for purchased power.[1]

A comparison of a non-firm commitment with a firm commitment of capacity discloses the salient aspects of this line of reasoning. A firm commitment of capacity by any single qualifying facility enables the utility to attribute to that facility a portion of the avoided capacity during any given hour of the planning horizon. In a sense, the contractual obligation relegates control of the committed capacity to the utility. In contrast, a non-firm commitment does not enable a utility to identify in advance the avoided capacity attributable to any single qualifying facility making a non-firm commitment. As noted above, the qualifying facility

[1]For limitations to this approach see the FERC rules.

retains control over the availability of capacity. The uncertainty of availability coupled with this lack of control substantially lowers the quality of the capacity-related product offered by non-firm commitments of capacity. One could argue that the utility should pay the cost of avoided capacity only for capacity for which it retains a degree of control over availability, much as if it had installed the capacity itself. The random availability of capacity implicit in a non-firm commitment of capacity fails to meet this standard. Thus, the exclusion of the cost of avoided capacity in rates for the purchase of non-firm power might be a desirable policy to adopt.

Term of Contract and the Cost of Avoided Capacity

With a firm commitment of capacity, a qualifying facility probably specifies the number of years for which the contract is signed. The term of the contract can affect capacity planning, and, therefore, the cost of avoided capacity. Rates for power purchased from facilities making firm commitments should include a cost of avoided capacity. This cost could be based on the costs of avoided capacity attributable to a contract of a given number of years. The resulting rate structure would encourage the commitment of capacity for the term that results in the greatest cost savings.

The cost of avoided capacity computed in the previous chapter is the annual cost of avoided capacity over the entire planning horizon. Aggregation of all firm commitments regardless of their duration introduces some internal subsidization into the rates based on this averaging of avoided cost. By disaggregating firm commitments of capacity according to short-term, intermediate-term, and long-term commitments of capacity and examining their effects separately, a cost justification for a rate structure based on the term of the contract can be developed.

The cost of avoided capacity attributable to any term of contract can be computed by the idealized method. This procedure requires clear definitions of the short, intermediate, and long term. For each term of the contract, the costs associated with two expansion plans are necessary. This general procedure is outlined below for each term of the contract.

A short-term commitment of capacity by a qualifying facility is considered here to be a commitment of one or two years. The effect on capacity expansion from the existence of such commitments must be considered separately from intermediate- and long-term commitments. To accomplish this, two capacity plans must be generated. The first expansion plan excludes all short-term commitments of capacity but includes all the intermediate- and long-term commitments. Associated with this expansion plan is a cost as given by equation 3.4 in the previous chapter. The second expansion plan includes all commitments of capacity by qualifying facilities. The difference between the cost associated with the first plan and that of the second yields the cost of avoided capacity as in equation 3.9. This cost of avoided capacity is the change in construction costs (C_t), the capacity credit (R_t), and operating costs (O_t) over the entire planning horizon attributable to the level of capacity committed by qualifying facilities under short-term contracts. This cost of avoided capacity is converted to an average annual cost according to equation 3.10 and distributed to the hours of the year according to the allocation factor (A_i). These hourly costs of avoided capacity are added to the hourly system lambdas and used to formulate rates for qualifying facilities making short-term commitments of capacity.

The foregoing procedure for short-term commitments is repeated for intermediate and long-term commitments of capacity. Intermediate-term contracts are considered here to be for a period less than the lead time for planned capacity expansion. This implies that the commitment of capacity for an intermediate period infringes on the construction period for units already under construction and to be added in the future, but will not be available on the estimated date of completion for these additional units. Long-term contracts, on the other hand, are defined to involve a time frame longer than the lead time for planned capacity expansion and possibly longer than the utility's planning horizon. For each term of the contract, the cost associated with two expansion plans is necessary to approximate the theoretical guidelines presented in chapter 3. The resulting rate structure, in which the cost of avoided capacity is based on the term of the contract, signals to potential and existing qualifying facilities which term of the contract yields the greatest cost savings. The signal allows qualifying facilities to plan their capacity more efficiently.

Commitments of Capacity to System Reliability

Qualifying facilities that commit their capacity on a firm basis during a utility's system emergency should be rewarded for this commitment. The FERC defines a system emergency as a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.[2] In these circumstances, the commitment of capacity reduces the capacity the utility must install to meet reliability standards. The avoided capacity extends to the system's reserve capacity. As a result, a megawatt of capacity committed under firm contract and also to a system emergency enables the utility to avoid installing more capacity than a megawatt committed under firm contract only.

The commitment of capacity during a system emergency means the qualifying facility making the commitment must make available to the utility the capacity under contract. This provision requires this regardless of the qualifying facility's need for the capacity. This differs from qualifying facilities making firm commitment but not making capacity available during a system emergency. In this case, a qualifying facility can divert all power output for its own use during a system emergency. This capacity does not make a contribution to system reserves and reliability.

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[2]See CFR Part 292.101(b)(4), 45 FR 12234

The cost of avoided capacity differs in these two cases. Qualifying facilities making a commitment of capacity during a system emergency displace reserve capacity that would otherwise have to be installed. This avoided capacity and the cost associated with it can be measured by generating two expansion plans. The first expansion plan would exclude all capacity committed during a system emergency, but would include all other commitments of capacity by qualifying facilities. The second expansion plan would include all capacity committed during a system emergency and all other commitments by qualifying facilities. With the costs associated with these two expansion plans, the idealized method can be used to compute the cost of avoided reserve capacity for the entire planning horizon. Once the average annual cost of avoided reserve capacity is quantified, the treatment of this cost of avoided capacity differs from the treatment of other types of commitments.

The cost of avoided reserve capacity can be used to develop a three-part tariff for qualifying facilities committing their capacity during a system emergency. The hourly cost of avoided reserve capacity is determined by using the allocation factor (A_i) to assign this cost to the hours of the year. These hourly costs are added to the applicable hourly costs of avoided capacity and the hourly system lambdas. These three costs are used to formulate a set of on-peak and off-peak prices. In this way, qualifying facilities that commit their capacity during a system emergency are rewarded for the additional cost savings the utility incurs.

Conclusion: A Rate Structure Based on the Avoided Cost of Service

Regulatory authorities can encourage an allocative efficient and welfare maximizing set of contracts between qualifying facilities and a utility by creating a rate structure based on the avoided costs of service. Such a price structure will signal to potential and existing qualifying facilities which kinds of commitments of capacity result is the greatest cost savings. The cost structure suggested in this section would result in the set of on-peak, off-peak rates based on the costs presented in table 4.1.

TABLE 4.1

Cost Structure Based on
Type of Capacity Commitment

Commitment of Capacity	Cost of Avoided Capacity	System Lambda	Cost of Avoided Reserve Capacity
Non-firm		X	
Firm			
Short-term	X	X	
system emergency	X	X	X
Intermediate-term	X	X	
system-emergency	X	X	X
Long-term	X	X	
system emergency	X	X	X

Source: Authors

There exist seven possible on-peak rates and seven possible off-peak rates. On-peak rates for the purchase of power from qualifying facilities making firm commitments of capacity consist of the costs of avoided capacity, including reserve capacity when applicable, and the system lambda. The on-peak rates for qualifying facilities making non-firm commitments are only the system lambda. All off-peak rates are equated to the system lambda. This rate structure rewards qualifying facilities according to the costs the utility is able to avoid due to the availability of their capacity.

Pricing At Less Than Avoided Costs

In formulating rates based on avoided costs, some public utility commissions may not wish to set rates equal to the avoided cost structure they quantify. This policy raises a series of issues that touch several areas of current regulatory practice. At the heart of the policy debate,[3]

[3]See Appendix A for commentary on the current legal debate (Spring 1982)

however, is the way in which the ultimate consumer of power is treated relative to the incentive imparted to qualifying facilities. There is a general consensus that power can be generated by cogenerators and small power producers at a lower cost than that incurred by utilities. Prices set equal to avoided cost fail to pass through any of this cost saving to the ultimate consumer. Furthermore, avoided cost is a marginal cost concept. Revenue requirements are based on some measure of the average cost of production which is believed to be lower than the marginal cost in recent years. This could create both equity and logistical problems because revenue requirements and rates to consumers may increase when the power purchased from qualifying facilities is priced at avoided costs as calculated by the marginal cost approach. Inter-utility transactions set a precedent for pricing purchased power. Here, half the fuel cost savings is passed through to the customer. The avoided cost standard for power purchased from qualifying facilities seems to ignore this current practice. Yet, to require rates for power purchased from qualifying facilities to conform to current practice would require the qualifying facility to submit cost of service filings and to participate directly in the regulatory arena. This direct participation would quickly dampen incentives to construct and operate a qualifying facility. By using the costs avoided by the utility, the direct participation of the qualifying facility is circumvented.

In this section, the effect of the marginal cost approach to calculating avoided costs is examined. From this analysis and the principles of the marginal cost approach, the cost-savings approach to calculating avoided cost is derived. The cost-saving approach is intended to assure that rates paid for power purchased from qualifying facilities will leave the revenue requirement unchanged.

Avoided Running Costs and Revenue Requirements

Prices being set at avoided costs may not be the primary determinant of how consumers fare. The rates consumers pay to the utility are based on the utility's revenue requirement. Avoided costs on the surface would seem to imply the consumer is left no worse off than if the utility generated the power itself. Yet if avoided cost is calculated as a marginal cost and the revenue requirement is based on an average cost, the consumer may be left worse off. Specifically, prices covering the marginal running costs for power purchased from a qualifying facility, which are calculated as a weighted average of hourly system lambdas, increase the revenue requirement. This cost of power purchased from a qualifying facility is passed through to consumers as an operating expense. A potential offset to this increase is the change in the utility's running cost attributable to serving a smaller load with the reoptimized system. The net effect of these changes may leave the consumer better off, worse off, or paying the same cost. The focus in this subsection is on the avoided running costs; the costs of avoided capacity are investigated in the next subsection. A mathematical formulation of this problem is presented in each subsection. It should provide a framework to help public utility commissions judge the appropriateness of a marginal cost approach to the calculation of avoided costs.

When the utility generates the power itself, the running costs that enter the revenue requirement are calculated on a unit-by-unit basis. Equation 3.7 in the previous chapter presents one possible approach to calculating this cost.[4] In the absence of power purchased from qualifying facilities, this cost of service (O_t) would enter revenue requirements. When this power is generated by qualifying facilities and priced at marginal running cost, the rates paid by consumers would change. The marginal running cost is the set of system lambdas the utility would have incurred if it did not purchase the power from qualifying facilities. If the rate covering marginal running costs are equal to the hourly system lambdas, the output from any qualifying facility would be purchased at this cost. This pricing practice severs the direct link between the running cost that would have been incurred by a unit and the revenues paid for its output.

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[4]Also, see footnote 1 of chapter 3.

The hourly system lambda (λ_{it}) is the cost of the next kWh generated on the system. It is calculated by picking an appropriate output point on the marginal unit's heat-rate curve and multiplying it by the cost per Btu of that unit's fuel. To this is added the change in nonfuel operation and maintenance expenses associated with an increase in output from the current level of output. The annual operating cost for power purchased from qualifying facilities can be expressed as

$$QFOR_t = \sum_i \lambda_{it} Q^{qf}_{it} \tag{4.1}$$

where

- i - an index of hours in the year.
- t - an index of years in the planning horizon.
- $QFOR_t$ - the annual operating costs that are paid to all qualifying facilities interconnected with the system.
- λ_{it} - the hourly system lambda in hour i of year t.
- Q^{qf}_{it} - the output purchased from all qualifying facilities in hour i of year t.

This cost associated with power purchased from qualifying facilities enters revenue requirements directly as an operating cost and is passed through to consumers.

The running costs incurred by the utility, when purchases from qualifying facilities are made, are given by equation 3.7 from the previous chapter. These running costs were labelled O'_t. This cost is calculated on a unit-by-unit basis and is included in the revenue requirement. The total running cost incurred by the utility for power it generates and purchases from qualifying facilities is given by

$$O'_t + QFOR_t \tag{4.2}$$

It is this cost that is included in the revenue requirement.

The annual change in the revenue requirement associated with operating costs (ΔORR_t) is given by

$$\Delta ORR_t = QFOR_t + O_t^{'} - O_t \tag{4.3}$$

It is the cost of power purchased from qualifying facilities plus the change in operating cost attributable to reoptimizing the system to meet reduced load growth. This change can be divided into two conceptual parts. The first is the change attributable to pricing output at marginal cost rather than average cost. The second is the change in the operating cost solely attributed to the new expansion plan. These two changes are discussed below.

The use of avoided costs creates a situation in which it is "as if" the qualifying facilities install the same type and size of capacity that the utility avoids installing. In this situation, the only difference introduced by the presence of qualifying facilities is the ownership of this capacity and the method by which output from it is priced. Thus, one could compute the running costs for each unit the utility avoids installing. Let $O_t^{''}$ be the running cost that is determined by quantifying the cost associated with dispatching the system with the reduction in load attributable to qualifying facilities, but dispatching the system using the original expansion plan on which avoided running costs are based. The difference between this running cost ($O_t^{''}$) and the original running cost (O_t) yields the change in running cost resulting from reduced load growth (O_t^A). Thus, the change in revenue requirements associated with operating costs that is attributable to the pricing method is given by

$$\Delta ORR_t^P = QFOR_t - O_t^A \tag{4.4}$$

where ΔORR_t^P - the annual change in revenue requirements to cover operating costs that results from pricing purchased power at system lambdas.

O_t^A - the running cost not incurred by the utility as the result of the purchase of power from qualifying facilities.

This change in revenue requirements is due to the excess of marginal cost over the average cost of production. So long as the system lambda increases with increased output, ΔORR_t^p will be positive. Thus, the practice of setting purchase prices equal to the system lambdas will tend to increase revenue requirements.

The second change in running costs, however, will offset this increase in revenue requirements. The reduction in load growth attributable to power purchased from qualifying facilities necessitates that the utility develop a new capacity expansion plan and operating strategy. The operating costs associated with this plan were quantified in chapter 3 using equation 3.7 and designated as $O_t^{'}$. The difference between this cost and the change in operating cost resulting from reduced load growth ($O_t^{''}$) yields the change in revenue requirements associated with operating costs that is attributable to reoptimizing the system to meet the reduced load growth at the minimum feasible cost. It is given by

$$\Delta ORR_t^{os} = O_t^{'} - O_t^{''} \tag{4.5}$$

where ORR^{os} - the annual change in revenue requirements to cover operating costs that is attributable to reoptimizing the system.

$O_t^{''}$ - the operating cost incurred by meeting the reduced load growth with the existing expansion plan.

The sum of the two annual changes in revenue requirements to cover operating costs yields the total annual change.

$$\Delta ORR_t = \Delta ORR_t^p + \Delta ORR_t^{os} \tag{4.6}$$

This annual change would be negative when the changes in the cost of service attributable to the substitution of a new expansion plan for the existing one results in a significant change in operating costs. A priori, the probability of this occurring seems low but is subject to investigation. What does emerge from this discussion, however, is the conclusion that pricing of power purchased from qualifying facilities at system lambdas does not necessarily mean revenue requirements are unchanged. In fact, they may very well increase. If this is the case, approximating avoided running cost by using system lambdas may not be consistent with traditional regulatory goals.

The Annual Cost of Avoided Capacity and Revenue Requirements

The marginal cost approach to the annual cost of avoided capacity can affect the revenue requirement in other ways. The annual cost of avoided capacity is a marginal cost and as such may result in revenues different from those associated with average cost pricing. Specifically, since the purchase of power from qualifying facilities supplements existing and planned capacity, both the size of the construction program and the operating costs are reduced. If this is the case, pricing the capacity related charges equal to the annual cost of avoided capacity may increase the revenue requirement. In this subsection, a mathematical formulation of this change in the revenue requirement is presented. This change along with the changes in the revenue requirement related to operating cost are combined in the next subsection to develop the cost-savings approach to avoided costs.

When the utility generates all of the power itself, the capacity related revenue requirements (CRR_t) for a year enter the cost of service both as a rate base entry and annual expense. Construction projects scheduled in the initial expansion plan, which are added to the rate base in years they enter service, are depreciated by the straight-line method and affect taxes. The revenue requirements in any given year during the planning horizon can be expressed as

$$CRR_t = (V + C_t - D)r + d + \frac{C_t}{\bar{L}} + \left(\frac{\alpha r tx^I}{1 - tx^I} + tx^P\right)C_t \tag{4.7}$$

where CRR_t - the annual capacity related revenue requirements for year t.

V - the value of used and useful property in service prior to year t.

D - the accumulated depreciation.

d - the annual depreciation expense for used and useful property in service prior to year t.

$\bar{L}$ - the average service life of units entering service in year t.

C_t, r, α, tx^I, and tx^P are the same as defined above in equations 3.4, 3.10 and 3.11. These capacity-related revenue requirements are the revenues that would be collected by the utility when no power is purchased from qualifying facilities.

The purchase of power from qualifying facilities using marginal cost based rates could substantially change capacity related revenue requirements. A rate base entry, a depreciation expense, and a tax expense are still calculated, although they are based on a different expansion plan. In addition, however, a capacity related charge enters revenue requirements as an operating expense. The cost of purchased power includes revenues paid to qualifying facilities based on the annual cost of avoided capacity. Herein lies the substantive difference in revenue requirements.

When purchases are made from qualifying facilities, the capacity related revenue requirement (CRR') can be expressed as

$$CRR'_t = \sum_i^{8760} A_i Q_{it}^{qf} (AAC_t) + (V + C'_t - D)r + d + \frac{C'_t}{\bar{L}} + \left(\frac{\alpha r tx^I}{1 - tx^I} + tx^P \right) C'_t \tag{4.8}$$

The annual cost of avoided capacity (AAC_t) is presented here as the cost for year t in the planning horizon instead of the annual cost of avoided capacity averaged over the entire planning horizon. This does not change any conclusion when the annual cost is averaged over the planning horizon; the cost in a given year only makes the problem at hand tractable.

The change in the capacity related revenue requirement is

$$\Delta CRR_t = CRR_t' - CRR_t \tag{4.9}$$

which is

$$\Delta CRR_t = \sum_i^{8760} A_i Q_{it}^{qf}(AAC_t) + (C_t' - C_t)r + \frac{C_t' - C_t}{\overline{L}} + \left(\frac{\alpha r tx^I}{1-tx^I} + tx^p\right)(C_t' - C_t) \tag{4.10}$$

This expression simplifies to the following

$$\Delta CRR_t = \left(\frac{Q_t^{on}}{\Delta K_t} - 1\right)\left[\frac{(1-tx^I-\alpha tx^I)r}{1-tx^I} + \frac{1}{\overline{L}} - tx^p\right](C_t - C_t') + \left(\frac{Q_t^{on}}{\Delta K_t}\right)\left[r + \frac{1}{n}\right](O_t - O_t') \tag{4.11}$$

where

$Q_t^{on} = \sum_i^{8760} A_i Q_{it}^{qf}$ - the on-peak purchases of power from qualifying facilities.

$\Delta K_t = K_t - K_t'$ - is the avoided capacity

All other symbols are defined previously.

The change in capacity related revenue requirements is in all likelihood positive. The first parenthetical expression in equation 4.11 is positive. $Q_t^{on}/\Delta K_t$ reduces to the number of hours it would take to generate the kilowatt-hours purchased on-peak by continuously purchasing power at the level of avoided capacity. This is positive and should exceed one. The second parenthetical expression is positive, negative or zero according to the relative magnitude of r, $\overline{L}$, tx^p and tx^I. The actual sign can be determined on a case-by-case basis. However, unless there is a very high property tax rate, this parenthetical expression should be positive.

The sign of the third term depends on the effect of purchases from qualifying facilities on the cost of construction projects entering service in year t. Given that the capacity to be installed over the planning horizon is scaled back to meet a reduction in load growth when power is purchased from qualifying facilities, there is strong a priori reason to suspect that this term is positive on average over the planning horizon. This term would be negative only in the case when reoptimizing the system and adjusting construction projects increase the cost of construction projects entering service. This outcome seems unlikely. The second term on the right-hand side of equation 4.11 is most likely positive also. The elements in the first two parenthetical expressions are positive, and so are these expressions. The third parenthetical expression is the change in operating cost attributable to reoptimizing the system to meet a reduction in load growth. This is most probably a cost savings, and, therefore, the term is positive. If these assumptions bear the weight of empirical investigation, the pricing of capacity related costs equal to the annual cost of avoided capacity as calculated by the marginal cost approach would tend to increase the revenue requirement.

Revenue Requirement Unchanged: Rates Based on the Utility's Cost Savings

Since the marginal cost approach to avoided cost for pricing power purchased from qualifying facilities will in all probability increase revenue requirements, and therefore rates paid by consumers, public utility commissioners and policymakers may not deem this a desirable outcome. Avoided cost on the surface implies that consumers are left no worse off because revenue requirements are left unchanged. In this subsection, a method for computing an avoided cost that leaves revenue requirement unchanged is presented. It is called the cost-savings approach to avoided costs. It is based on equations 4.3 and 4.10. Both the capacity related costs and the operating costs are allocated to the hours of the year so that an on-peak, off-peak pricing tariff may be developed.

The operating cost savings that leave the revenue requirement unchanged would be an average cost saving computed on an annual basis. For pricing purposes, it would be desirable to have this cost reflect the time pattern of marginal cost. A resulting set of on-peak, off-peak prices would signal to qualifying facilities when their availability displaces higher operating costs.

The change in revenue requirements associated with operating cost is given by equation 4.3. It is

$$\Delta ORR_t = QFOR_t + O_t' - O_t \tag{4.12}$$

Setting this change equal to zero and solving for the revenues to cover operating costs that are paid to qualifying facilities ($QFOR_t$) yields

$$QFOR_t = O_t - O_t' \tag{4.13}$$

These revenues are equal to the change in running costs associated with the two expansion plans.

A set of on-peak, off-peak rates for energy costs can be developed by assigning this cost savings per unit of avoided output to the hours of the year. The assignment factor should accomplish a minimum of two goals. First, as stated above, the assignment of these costs should reflect the time pattern associated with marginal running costs. Second, the cost saving per unit of avoided output should be fully recovered over the demand cycle.

These goals are achieved by the following allocation factor

$$F_{it} = \frac{\lambda_{it} Q^{qf}_{it}}{\sum\limits_{i}^{8760} \lambda_{it} Q^{qf}_{it}} \tag{4.14}$$

where

$$\sum_{i}^{8760} F_{it} = 1 \tag{4.15}$$

The allocation factor for operating costs (F_{it}) is based on the set of hourly system lambdas used in the marginal cost approach to the avoided cost. This allocation factor assigns the cost savings per unit of avoided output to the hours of the year according to the percentage of revenues that all qualifying facilities would receive in each hour if rates were based on the system lambdas. In doing this, the assignment of the cost savings to the hours of the year reflects the time pattern of the marginal running cost over the annual demand cycle. The condition given by equation 4.15 assures the cost savings is completely paid to qualifying facilities for the power they provide. In sum, the hourly operating costs savings (OCS_{it}) per unit of avoided output can be expressed as

$$OCS_{it} = \frac{F_{it}}{\sum\limits_{i}^{8760} Q^{qf}_{it}} (O_t - O'_t) \tag{4.16}$$

where $\sum\limits_{i}^{8760} Q^{qf}_{it}$ is the annual avoided output. This hourly cost is used in conjunction with the hourly capacity cost savings to develop a system of on-peak, off-peak rates.

The capacity cost savings that leaves the revenue requirement unchanged is based on equation 4.10. The annual capacity related revenue requirements paid to qualifying facilities is given by

$$\Delta CRR_t = \sum_i^{8760} A_i Q_{it}^{qf} (AAC_t) + (C_t' - C_t)r + \frac{C_t' - C_t}{\overline{L}} + \left(\frac{\alpha r tx^I}{1 - tx^I} + tx^P \right)(C_t' - C_t)$$

Setting this change in the capacity related revenue requirements equal to zero and recalling that

$$Q_t^{on} = \sum_i^{8760} A_i Q_{it}^{qf}$$

yields the annual revenue paid to qualifying facilities to cover the capacity related cost savings. It is

$$Q_t^{on}(AAC_t) = (C_t' - C_t)r + \frac{C_t' - C_t}{\overline{L}} + \left(\frac{\alpha r tx^I}{1 - tx^I} + tx^P \right)(C_t' - C_t) \tag{4.17}$$

The annual capacity related cost savings is the sum of the return on the change in construction costs associated with reoptimizing the system to meet reduced load growth plus the associated change in the annual depreciation expense plus the change in the utility's income and property tax liability. This cost savings per unit of output avoided during the on-peak period is allocated to the hours of the year using the allocation factors A_i. Thus, the hourly capacity related cost savings (CCS_{it}) per unit of avoided output is given by

$$CCS_{it} = \frac{A_i}{Q_t^{on}} \left[(C_t' - C_t)r + \frac{C_t' - C_t}{\overline{L}} + \left(\frac{\alpha r tx^I}{1 - tx^I} + tx^P \right)(C_t' - C_t) \right] \tag{4.18}$$

Equations 4.16 and 4.18 are combined to yield the hourly cost saving (CS_{it}) per unit of avoided output.

$$CS_{it} = OCS_{it} + CCS_{it} \tag{4.19}$$

A weighted average of these hourly costs can be used to develop a system of on-peak, off-peak rates for power purchased from qualifying facilities. The purchase of the hourly (avoided) output from qualifying facilities for the entire year will recover the annual cost savings experienced by the utility. It is

$$\sum_{i}^{8760} CS_{it}\, Q_{it}^{qf} = (O_t - O_t') + (C_t' - C_t)r + \frac{C_t' - C_t}{\overline{L}} + \left(\frac{\alpha r t\frac{I}{x}}{1 - t\frac{I}{x}} - \frac{p}{tx}\right)(C_t' - C_t) \tag{4.20}$$

The inclusion of this cost of power purchased from qualifying facilities in the utility's revenue requirements will leave rates to consumers unchanged.

Summary

The idealized method for calculating avoided costs presented in the previous chapter allows a public service commission to include several features in the calculation. A commission could set rates for the purchase of power that signal to qualifying facilities that firm commitments of capacity result in greater cost savings than non-firm commitments of capacity; that longer-term commitments of capacity may result in a greater cost saving than intermediate or short-term commitments; and that a commitment of capacity during system emergencies generates a cost saving. In addition, the rates could also signal to the qualifying facility that energy produced on-peak creates greater cost savings than energy generated off-peak. However, this method also has limitations. It does not take into consideration either cost-based deviations from the average annual cost of avoided capacity or the equity and logistical problems that may be created because revenue requirements and rates to consumers may increase when the power purchased from qualifying facilities are priced at fully avoided costs. A state public service commission may wish to modify the idealized method presented in the previous chapter to take into account these considerations.

One of the more important of these considerations is the effect of an avoided cost rate on the revenue requirement. There exists a strong likelihood that the idealized method presented in the previous chapter may increase the revenue requirement. A public utility commission may wish to use the procedures described in this chapter to leave revenue requirements unchanged.

The following list is presented in summary of the main themes discussed throughout chapters 3 and 4. A desirable method of calculating avoided cost would have the following features.

1. Revenue requirement does not increase as a result of purchasing power at avoided cost

2. Avoided capacity costs reflect adjustments to the utility's expansion plan that are attributable to purchases from qualifying facilities

3. Adjustments to the utility's normalized load curve are based on potential commitments of capacity on a firm and non-firm basis

4. Potential commitments of capacity by qualifying facilities, regardless of the size of the commitment, are aggregated for purposes of adjusting the normalized load curve

5. The avoided cost of capacity reflects the change in the utility's income tax and property tax liability

6. The avoided cost of capacity is linked to changes in the operating cost experienced by the utility

7. The payment of the avoided costs of capacity to qualifying facilities reflects the probability that the utility might experience a demand that exceeds its available capacity

8. The payment of the avoided costs of capacity to qualifying facilities reflects the duration of a capacity commitment if that affects the cost savings

9. The commitment of capacity by a qualifying facility during a utility's system emergency is rewarded and the reward reflects the cost of avoided reserve capacity

10. Avoided running costs reflect the hourly variation in system lambdas experienced by the utility or pool

This summary of the avoided cost emphasize the cost of avoided capacity. In particular, reoptimization of the system based on reasonably expected commitments of capacity by qualifying facilities is crucial. Furthermore, this summary can serve as a standard by which to evaluate rates negotiated between a qualifying facility and the utility.

CHAPTER 5

PRACTICAL METHODS OF CALCULATING AVOIDED COST

The descriptions in chapter 2 of the avoided cost calculation methods of various state commissions indicate a diversity of approaches currently in use for setting rates for purchases from qualifying facilities. This chapter contains a presentation of some major practical methods for calculating avoided costs, based upon the various approaches used in estimating avoided costs of various state commissions. Each major practical method of estimating the avoided costs associated with utility purchases from cogenerators and small power producers will be described and then analyzed in terms of its theoretical appropriateness compared to the idealized method developed in chapter 3. In addition, each method's feasibility and compliance with FERC rules will be examined in detail.

Among the alternative practical methods of calculating avoided costs, the more analytical methods do not necessarily yield avoided cost estimates which are more accurate than those estimates provided by much simpler methods. Typically, the more analytical avoided cost methods which are similar to the idealized approach require information such as forecasts of hourly utility loads, the output from qualifying facilities, future fuel prices, future interest rates, etc. The weakness of existing forecasting techniques implies that the forecasted inputs required by the more analytical avoided cost models are a source of considerable inaccuracy in the resulting avoided cost estimates.

In choosing an avoided cost method, the more analytical methods yield results that may be more satisfying, in that given perfect forecasting inputs, the models will estimate avoided cost with precision. However, given the introduction of forecasting errors into the input of these models, the overall accuracy of the more analytical avoided cost models in estimating avoided cost may not be significantly better than that provided by simpler methods. In selecting an avoided cost method, it is important to bear in mind the tradeoff between the additional costs of computers, computer time, and personnel associated with using more elaborate calculation techniques and the expected benefits of improvement in the resulting estimates.

This chapter begins with an analysis of just how practical the idealized method presented in chapter 4 is. The practical methods presented in succeeding sections include the long-run marginal cost methods, the short-run marginal cost methods, the purchased power approaches, the reverse-the-meter approaches, the differential revenue requirements approaches, and the simplified average incremental cost methods.

The Feasibility of the Idealized Method

The idealized method developed in chapter 4 may present implementation problems for some public service commissions, and for some commissions may be infeasible. This is because the idealized method relies heavily on simulations of the economic dispatch of the system over the planning horizon; and, to simulate an optimal capacity expansion plan, it is necessary to forecast future load. Load forecasting simulation of optimal capacity expansion plans, and production cost simulation of the economic dispatch of the system are difficult to perform with great accuracy without the assistance of computer models. Because use of computer models is needed for the idealized method, a public service commission would need computer facilities, the appropriate computer programs, and the ability to collect and verify input data for the computer programs in order to use the idealized method itself. Each of these requirements is discussed here. A commission might choose to direct the company to perform the calculations called for in this method, however, even if it did not itself meet each of these requirements. Commissions that prefer non-computer techniques might choose one of the avoided cost approximations discussed later in this chapter.

Need for Computer Facilities

Because the idealized method to determine avoided costs is based on computer programs and models, access to computer facilities is a determining factor in the applicability and feasibility of this method. Without access to computer facilities, public service commissions are limited in their capabilities for review of submitted avoided cost calculations and in their analysis of appropriate approaches. In a recent NARUC survey of the electronic data processing (EDP) capabilities of public service commissions,[1] twenty-four commissions were reported to use computers. Of these, all but one reported having support EDP staff. While nearly half the public service commissions reported having computer facilities and could be expected to have the capability to undertake the idealized method calculations, the remaining commissions' ability to apply the idealized method is limited in this regard.

Need for Computer Programs

The idealized method of calculating avoided costs is based on a number of models, i.e., load forecasting, optimal capacity expansion planning, and production cost simulation models. These models have been incorporated into computer programs, and thus, again, in order for the commission to evaluate utilities' calculations using the idealized approach, these programs must be accessible. A number of these models are available from commissions and other sources. This section provides an overview of the programs necessary for calculating avoided costs and their availability.

Energy demand and load forecasting models attempt to predict and explain changes in future demand for electricity. There are a number of

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[1]See National Association of Regulatory Utility Commissioners, 1980 Annual Report on Utility and Carrier Regulation, (Washington, D.C.: 1981), pp. 531-532.

models available, but no one model is generally preferred over others.[2] Load forecasting models can be categorized into two general types, econometric and engineering approaches. Many specific forecasting models, though, are actually hybrids of these two approaches.

The econometric forecasting models seek to explain the demand for electricity in terms of various economic indicators such as the level of electric prices, income, population, and other factors. Engineering forecasting models (also called end-use models) attempt to determine future levels of demand by modeling electric appliance saturation rates and utility load curves. Engineering models, in general, are more appropriate for the prediction of short-run future demand since changes in overall demand are the result of shifts in rates of use of particular appliances. For long-run predictions of demand, it may be more appropriate, though, to model that demand with an econometric model.[3]

Table 5-1 lists a number of the load and energy forecasting models available to public service commissions. Many commissions rely only on the forecasts provided by utilities; others, though, analyze these forecasts or perform their own in-house forecasting. A number of commissions hire consultants to make load forecasts when required and a few rely on forecasts from state energy offices. Table 5-2 lists commissions' efforts in forecast development and analysis.

Load forecasts provide necessary input for capacity planning models, since the decision to build generating capacity is directly related to

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[2]See The National Regulatory Research Institute, Load Forecasting and Capacity Planning: Current Availability and Usage, (Columbus, Ohio: The National Regulatory Research Institute, 1979), for an overview of these models.

[3]Ibid., pp. 3-5.

TABLE 5-1

LOAD AND ENERGY DEMAND FORECASTING MODELS

Program Name/Description	Source/Availability
SLED State-Level Electricity Demand	U.S. Nuclear Regulatory Commission (NUREG/CR-1295, ORNL/NUREG-63) (Developed by Oak Ridge National Laboratories)
P34 Various econometric models for long-run and short-run forecasting	Missouri Public Service Commission
FORECASTING uses time series data	Missouri Public Service Commission
ICF LOAD IMPACT MODEL	South Carolina Public Service Commission (Developed by ICF, Inc.)
LIM Load Impact Model	North Carolina Utilities Commission

Source: The National Regulatory Research Institute, Letter Report on the Model Dissemination and Use Project. Columbus, Ohio: NRRI, 1982, pp. 83, 84, 95, 96, 258, 264.

TABLE 5 - 2

COMMISSION INVOLVEMENT IN LONG-RANGE ELECTRIC UTILITY LOAD FORECASTING

Commission	Relies on Utility Forecasts	Analyzes or Reviews Utility Forecasts	Performs In-house Forecasting	Hires Consultants for Forecasting	Forecasting Performed by State Energy Office
Alabama PSC	Yes				
Alaska PUC	No	No	No	No	
Arizona CC	Yes				
Arkansas PSC	Yes				
California PUC			Yes		
Colorado PUC					
Connecticut DPUC	Yes	Yes			
Delaware PSC	Yes			Yes	
District of Columbia PSC				Yes	
Florida PSC			Yes		
Georgia PSC	Yes			Yes	
Hawaii PUC	Yes				
Idaho PUC		Yes		Yes	
Illinois CC	Yes	Yes			
Indiana PSC	Yes				
Iowa SCC	Yes	Yes	Yes	Yes	
Kansas SCC	Yes	Yes	Yes		
Kentucky PSC	Yes				
Louisiana PSC	Yes				
Maine PUC	Yes	Yes		Yes	
Maryland PSC		Yes			
Massachusetts DPU					
Michigan PSC		Yes			
Minnesota PUC	Yes				
Mississippi PSC	Yes				
Missouri PSC		Yes	Yes		
Montana PSC	Yes				
Nebraska PSC					
Nevada PSC	Yes		Yes	Yes	
New Hampshire PUC	Yes		Yes		
New Jersey BPU	Yes				
New Mexico PSC	Yes		Yes	Yes	
New York PSC			Yes		Yes
North Carolina UC			Yes		
North Dakota PSC	Yes				
Novia Scotia PUB	Yes			Yes	
Ohio PUC					Yes
Oklahoma CC	Yes			Yes	
Oregon PUC			Yes		
Pennsylvania PUC		Yes			
Rhode Island PUC					
South Carolina PSC	Yes	Yes	Yes		
South Dakota PUC	Yes				
Tennessee PSC					
Texas PUC	Yes				
Utah PSC				Yes	
Vermont PSB		Yes			
Virginia SCC		Yes	Yes		
Washington UTC	Yes				
West Virginia PSC	Yes	Yes			
Wisconsin PSC		Yes		Yes	
Wyoming PSC	Yes				

Source: National Association of Regulatory Commissioners, 1980 Annual Report on Utility and Carrier Regulation, (Washington, D.C.: NARUC, 1981), p. 675, Table 70.

projected load growth. Optimal capacity expansion planning models seek to determine the appropriate unit size, the date each unit comes on line, and the generation technology of additions to the electric utility's plant.[4] Numerous capacity planning models are generally available to public service commissions to evaluate utility planning efforts. Several of these models are listed in table 5-3. A major problem with the available models is that they require large amounts of data and significant computer resources. Not all commissions have the staff needed to maintain and utilize such models. However, they can be very important to commissions in analyzing utility expansion plans for the objective of reducing the capital needs of the utility industry.[5]

A third type of model needed in the idealized method of calculating avoided costs is a production cost simulation model. Such models can help identify areas where more efficient utilization of resources can be made. Thus, they are important to regulatory commissions, in relation to PURPA's goal of attaining a more efficient utilization of resources.[6] More specifically, these models are useful in estimating energy costs with and without cogenerators. Several energy cost estimation models exist in the public sector and are available to commissions having the necessary computer facilities. Table 5-4 lists some of these programs.

The Need for Data Collection and Verification

To calculate properly the idealized method to determine avoided costs and analyze utilities' submissions of avoided costs, public service commissions must have access to the data used in such calculations and the models discussed above. While the data are available from a number of sources,

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[4]The National Regulatory Research Institute, 1979, p. 5. See also, pp. 6 and 11 for further discussion of capacity planning models.

[5]Ibid., pp. 11 and 14.

[6]Ibid., p. 14.

TABLE 5-3

OPTIMAL CAPACITY EXPANSION PLANNING MODELS

Program Name/Description	Source/Availability
WASP WEIN AUTOMATIC SYSTEM PLANNING	Missouri Public Service Commission (Developed by the Tennessee Valley Authority)
Over/Under Capacity Planning Model	State Corporation Commission of Kansas Connecticut Department of Public Utility Control (Developed by Electric Power Research Institute (EPRI))
CAPPLAN An over/under capacity planning model	North Carolina Utilities Commission (Developed by Decision Focus, Inc.)
CEM Capacity Expansion Model	North Carolina Utilities Commission
CAPACITY1 Capacity Optimization, Generation Planning	North Carolina Utilities Commission
CERES Capacity Expansion and Reliability Evaluation Study	Developed by the National Regulatory Research Institute (NRRI)
ICF Supply Model Capacity Expansion, Production Cost	South Carolina Public Service Commission (Developed by ICF, Inc.)
OGP Optimized Generation Planning	Proprietary Model developed by General Electric

Source: The National Regulatory Research Institute, Letter Report on the Model Dissemination and Use Project. Columbus, Ohio: NRRI, 1982, pp. 68, 69, 83, 88, 202, 203, 268, 269. The National Regulatory Research Institute, Load Forecasting and Capacity Planning: Current Availability and Usage. Columbus, Ohio: NRRI, 1979.

TABLE 5-4

ENERGY COST ESTIMATION MODELS

Program Name/Description	Source/Availability
PCS Production Cost Simulation Model	State Corporation Commission of Kansas Oklahoma Corporation Commission (Developed by The National Regulatory Research Institute (NRRI))
MARG Marginal Energy Costs (Modification of PCS)	State Corporation Commission of Kansas
Production Cost Analysis (Modification of PCS)	Virginia State Corporation Commission
PCM Production Costing Model	Connecticut Department of Public Utility Control
PRODCOST Production Cost Analysis Program	Pennsylvania Public Utility Commission
PROMOD III Production Cost and Reliability System	Proprietary-Energy Management Associates, Inc.

Source: The National Regulatory Research Institute, Letter Report on the Model Dissemination and Use Project. Columbus, Ohio: NRRI, 1982, pp. 90, 262, 263, 274-278.

the ease with which commissions can obtain the data varies depending upon the source. Furthermore, once obtained, the data must be verified for accuracy, and problems may occur in this respect as not all data will be verifiable.

One source from which data can be obtained with relative ease is information filed under legislative mandate. Under the Federal Power Act, utilities must submit operational and financial data to the Federal Energy Regulatory Commission on FERC Form 1. The information filed must conform to the Uniform System of Accounts. Data to be reported include assets and liabilities, electric plant accounts, operating expenses and revenues, retained earnings, and income and deductions. These data are available to public service commissions and also the general public in Statistics of Privately Owned Electric Utilities in the United States.[7]

The Public Utility Regulatory Policies Act of 1978 (PURPA) also requires the filing of information by utilities which can be utilized by commissions in preparing and evaluating avoided cost calculations. Section 133 of PURPA requires that certain information be filed by utilities with the FERC, with copies of this information forwarded to state commissions. Data to be reported should be filed in accordance with the FERC Uniform System of Accounts, where applicable, and must include accounting cost information, marginal cost information, and load data. Specific accounting cost information includes data pertaining to rate base determinations, and rate of return information. Marginal cost information to be filed includes production planning information for existing generating plants and for planned additions to generating capacity, information on factors affecting existing generating units, resource projections, and energy, transmission, distribution, customer and other cost information. Load data are to be provided for a total of all customers and for certain customer groups.

[7]Published by the Energy Information Administration of the U.S. Department of Energy.

Section 210 of PURPA also requires electric utility systems to provide cost data to public service commissions. These data include estimated avoided costs to the utility, the utility's plans for capacity expansions, purchases and retirements, and estimates of the associated capacity costs.

The information provided in these required reports can supply commissions with much of the data needed to determine avoided costs. However, because some of these data are based on projections, or are otherwise generated from models, additional information from other sources is often necessary to verify results of models. Commissions might seek this additional information from utilities during rate cases, or if such data are not readily available, the commission, by special order, might require the utilities to undertake special studies. Information requested of utilities, thus, might be available to commissions with varying degrees of ease and accessibility.

Commissions may also approach consultants for the background information needed to verify projections. Information from this source, however, may be expensive. Furthermore, obtaining certain data may require special studies which can be time consuming.

As mentioned, some of the data available from public sources is generated from models. Input to these models may depend on results from other modeling efforts. Thus, a commission might want to verify the output from each model. To do so, the commission must have access to each model or program along with the necessary input data.

Long-Run Marginal Cost Methods

The long-run marginal cost methods of determining avoided costs can be classified as specific unit approaches and expansion planning approaches. Since the use of purchased power rates as a means of estimating avoided costs in both the short and long runs will be examined in a separate purchased power section of the chapter, this section is devoted to the consideration of specific unit and expansion planning approaches.

The specific unit approaches use the expected capacity cost and running costs of a future base load unit to estimate the long-run avoided costs of capacity and energy. The capacity costs are annualized over the expected life of the generation facility to yield an annual capacity cost per kW. The process of annualizing the total capacity costs may involve either the application of a carrying charge to the total capacity cost per kW or the use of present value and annuity calculations.

When the relatively high capacity costs of a base load unit are used in calculating avoided capacity cost credits, it is important that the relatively low energy cost of this base load unit also be used in estimating the avoided energy costs. To use the high capacity costs of a base load unit and the high energy costs of a peaker as estimators of avoided capacity costs would grossly exaggerate the avoided costs made possible by the output of qualifying facilities.

An advantage in using a specific unit approach in estimated long-run avoided capacity and energy costs is the simplicity of acquiring information and making the necessary calculations. Operating data from similar existing generation units are typically available to allow a precise and verifiable estimate of the energy costs of this facility. In addition, the generating plant construction industry can provide estimates of the expected capital costs per kW of capacity. However, the estimation of the future cost of constructing the new facility is a potential source of disagreement in applying this calculation method.

When compared with the idealized method for calculating avoided costs, the use of a single future generation facility to estimate avoided costs has significant deficiencies. This approach implicitly assumes that the output from qualifying facilities will be sufficient to permit the elimination of a future base load unit. For many utilities this would be a manifestly unrealistic prospect. A more reasonable approach is to allow for capacity cost savings based on the deferral of a new generation facility or a change in the mix of new generation facilities.

This method also ignores the expected timing of power deliveries from qualifying facilities and its affect on avoided energy costs. The output from qualifying facilities will, during various hours over the course of a year, be replacing energy generated by base load, intermediate, and peaker units.

The use of estimated costs from a specific base load plant does not provide for a reoptimization of the utility system based on the output of qualifying facilities. Hence, it does not produce a theoretically satisfying means for estimating the long-run avoided costs of the utility system, when it is viewed as an integrated whole.

The value of this method is that it can produce a crude estimate of avoided costs which is simple to compute and may serve as a means of checking the results of more complex methods. Any extreme discrepancy between the two avoided cost estimates is likely to result either from the simplicity of the specific unit approach or from an error in applying the more complex approach.

Expansion planning and long-run production cost models permit a reoptimization of the utility's mix of generation capacity, and, thus, produce avoided costs which are truly long run in nature. The idealized method is one such long-run marginal cost method. The required inputs to such models include load forecasts over the planning horizon, price forecasts for construction and other costs, estimates of future output from qualifying facilities, and data on the operating characteristics of existing and future generation facilities. The least-cost expansion plan is found for the case where there are no qualifying facilities, and then an expansion plan is developed which takes into account the expected output from qualifying facilities. The difference in the present value of cost flows between the two plans can be used to estimate the avoided energy and capacity costs made possible by utility purchases from qualifying facilities.

Feasibility of Long-Run Marginal Cost Methods

Long-run marginal cost methods can be used to estimate utilities' avoided costs based on the capacity and energy costs avoided as a result of purchases from cogenerators. A number of methods, varying in complexity, exist for calculating long-run marginal costs. The more sophisticated estimation procedures (the expansion planning approaches) involve forecasting, use of large data banks, and extensive computer simulation, and thus, can be expensive. On the other hand, simpler, shorthand approaches (such as the specific unit approaches) are available and less expensive, but the validity of the estimates they produce must be judged in light of the simplifying assumptions they contain. In selecting a long-run marginal cost method, a commission must consider such tradeoffs in the context of its available resources.[8]

While the more elaborate methods may be considered idealized because of the sophistication of the forecasts, information, and computer models on which they are based, there are also practical limitations imposed by these same features. The forecasts involve use of computer models which may not be in the public domain, and thus, not readily accessible by state commissions. Furthermore, these methods, forecasts, and models rely on certain items of data which might be difficult to acquire. At a minimum, data requirements of PURPA Section 133 can be used as input. However, additional information may be required, depending upon the complexity of the model used. To acquire these additional data a commission might request additional submissions by utilities; however, some of this data might not be readily available, and a commission may need to order a utility to undertake a special study.

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[8]For a further discussion, see Roger McElroy, et al., Marginal Cost Ratemaking for Cogeneration, Interruptible, and Back-up Services (Columbus, Ohio: The National Regulatory Research Institute, 1981), p. 27.

A simplified long-run marginal cost method is the MARGINALCOST program. The MARGINALCOST approach incorporates a computer program developed by Cicchetti, Gillen, and Smolensky.[9] MARGINALCOST does not rely on the forecasting and capacity expansion models of the more complex long-run marginal cost methods; and although it typically requires the use of computer facilities, the calculations can be performed by hand in a few hours with the aid of a calculator.[10] Additionally, the MARGINALCOST program is readily available to commissions because it is in the public domain.

In addition to accessibility to computer facilities and programs, the feasibility of avoided cost approaches is dependent on data availability. MARGINALCOST relies primarily on data, most of which is available through submissions pursuant to PURPA Section 133; however, additional information may also be necessary. Again, as with other long-run marginal cost approaches, this additional information may not be readily available. Thus, while MARGINALCOST is a simplified method, its feasibility from a commission's point of view may be limited with respect to data availability.

In sum, the extent to which the various long-run marginal costing approaches are practicable from a commission's viewpoint is necessarily dependent upon the complexity and nature of the specific method employed. Particular methods vary in data, computer, and modeling requirements, and, thus, vary in feasibility.

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[9] See 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, Sacremento, 1977. The MARGINALCOST program is based on the work of Ralph Turvey, in <u>Optimal Pricng and Investment in Electricity Supply</u> (Cambridge: MIT Press, 1968). For further explanation of MARGINALCOST, see Stephen N. Storch, <u>A Users Manual for MARGINALCOST, A Computer Program developed by Charles J. Cicchetti</u>, (Columbus, Ohio: The National Regulatory Research Institute, 1977) and Roger McElroy et al., pp. 37-40.

[10] SeeCicchetti, Gillen, and Smolensky, op cit.

Compliance with FERC Rules

Because incremental costs are essentially marginal in nature, long-run marginal cost methods will comply with the FERC rules concerning the calculation of avoided costs. The federal Energy Regulatory Commission noted in its comments to the final rules "that the translation of the principle of avoided capacity costs from theory into practice is an extremely difficult exercise." The Federal Energy Regulatory Commission has, therefore, allowed the state public service commissions the flexibility for experimentation. Because long-run marginal cost methods reasonably account for the utility's avoided costs and do not fail to provide the required encouragement of cogeneration and small power production, long-run marginal cost methods are satisfactory methods of implementing the FERC rules.

Short-Run Marginal Cost Methods

Short-run marginal costs include the fuel, operating, maintenance, and all other costs that vary with changes in a utility's energy output, assuming no change in the utility's plant and equipment. Thus, short-run marginal costs exclude the fixed costs associated with the utility's investment in generation, transmission, and distribution plant since it is assumed that these cannot change significantly over a short time frame. In contrast, long-run marginal costs reflect the full cost, including possible new plant and equipment costs, of generating additional units of electricity over a time frame long enough to change the utility system itself.

Two rationales are cited in support of the use of short-run marginal costs in estimating the costs avoided by utilities in making purchases from cogenerators and small power producers. Excess capacity on the part of a purchasing utility and the unreliable nature of non-firm power from qualifying facilities are the reasons most frequently given for basing payments to qualifying facilities on short-run marginal costs.

In some areas, the purchasing utility may have significant excess capacity. Excess capacity is often characterized by a very low loss-of-load probability for the system and a suspension of any new generation plant construction. Under these circumstances, the utility's purchase of power from cogenerators and small power producers will not allow the utility to avoid any generation plant expenditures, since none is planned.[11]

If the purchasing utility can wheel power from qualifying facilities to other utilities that need capacity, capacity payments to qualifying facilities might be based on the avoided capacity costs of the final purchasing utility. When power from qualifying facilities cannot be economically wheeled to a utility which needs capacity, no capacity costs are avoided, and therefore the qualifying facilities' purchase payments might reflect only the short-run marginal costs that the utility avoids.

A variation of the excess capacity argument in favor of using short-run marginal costs is based upon the contractual requirements associated with long-term purchased power. A non-generating utility which purchases power under a long-term contract with fixed capacity payments cannot avoid any capacity costs by replacing purchased power from its major supplier with power from qualifying facilities. Thus, since the non-generating utility can avoid only fuel and other variable costs by reducing purchases from its wholesale supplier, these short-run marginal costs are the basis for payments to qualifying facilities until the wholesale purchase contract of the non-generating utility can be modified to reflect its reduced need for capacity.

A second rationale for the short-run marginal cost pricing of power from qualifying facilities is that the unreliable nature of non-firm power from qualifying facilities eliminates the potential for avoided capacity costs on the part of the purchasing utility. When many qualifying

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[11]The FERC will allow a capacity credit of the present value of future capacity additions deferred due to purchases from qualifying facilities. See Reg. §292.304(e)(3), 45 FR 12236.

facilities sell non-firm power to a utility, in the aggregate some portion of this power is likely to be available all the time and will permit the utility to avoid some capacity costs. However, the difficulty in estimating statistically the firm component of non-firm power may make the accurate calculation of capacity credits for non-firm power infeasible. However, a commission could set the capacity credit payment at a reasonable figure as a matter of policy.

There are several major approaches for the estimation of short-run marginal costs, although these methods appear in practice with many variations. Short-run marginal costing methods for estimating avoided costs can be classified as single unit approaches, incremental heat rate approaches, and production costing approaches.

The single unit approach uses the running costs of a single generation facility to estimate the avoided short-run marginal costs to the system. By selecting a peaking unit this method estimates the maximum avoided fuel and operating and maintenance costs made possible by the purchase of power from qualifying facilities during peak hours.

A variation of this approach uses data from a peaking facility and a base load plant to estimate the avoided running costs during peak and off-peak periods respectively. The two generating unit approach more accurately tracks the actual avoided running costs over time than the use of a single unit.

One advantage of using the marginal running costs of an existing generation unit or units to estimate avoided energy costs is that this estimate is objectively determined from existing utility data on plant operating characteristics. More sophisticated avoided cost methods typically require estimates of such factors as future interest rates, fuel prices, the utility's load growth, and the output from qualifying facilities.

Forecasts of factors which affect a more analytical avoided cost calculation method, using current state-of-the-art forecasting techniques, are often weak at accurately predicting the future. In addition, analysts will disagree over what constitutes a reasonable forecast for these variables. Hence, the possibility that the user of a more analytical model will not select those forecasts of critical variables which yield the accurate result may impair the objectivity of a sophisticated estimate of avoided costs.

Not only is the single unit method relatively easy to use in estimating avoided costs but it also yields objective results which can be verified by an audit of the operating data from existing plants. Hence, as a means of estimating avoided short-run marginal costs, the single unit method is practical and objective.

The main theoretical problem with this approach is that it, at best, can only crudely approximate the marginal running costs of the utility system as a whole. Every utility with a sophisticated dispatching system controls the operating level of each generating plant so as to minimize the variable costs of meeting load at each moment in time. Hence, the efficiency of every generation plant in the utility system is relevant in estimating the true marginal running cost of the utility system as a whole.

Another problem in using the marginal running costs of specific generation units to estimate the system's marginal running costs is that the effect of changes in load over time on marginal system running costs is recognized only partially. Using the marginal running costs of a peaker and a base load unit to estimate peak and off-peak running costs ignores the innumerable variations in load and, hence, marginal running costs between these two load demand extremes.

The incremental heat rate approach provides another means for estimating system marginal running costs. This approach involves the estimation of system heat rates[12] for serving specific increments in system load.

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[12] A heat rate indicates the efficiency with which a generating unit or system of units transforms heat energy measured in British thermal units (Btu) into electrical energy measured in kilowatt-hours (kWh).

The incremental system heat rate is often calculated for two load levels: peak and off-peak. Information on the price and Btu content of fuel is combined with the incremental heat rate to yield an estimate of the marginal fuel cost which is the dominant component of marginal running costs. By adding estimates of the marginal operating and maintenance costs to the marginal fuel cost derived from the incremental system heat rate, an estimate of system marginal running costs for the specified load increment is produced.

The incremental heat rate approach is similar to the specific unit method for estimating marginal running costs. While the specific unit method relies on data from an individual plant to make cost estimates, the incremental heat rate method uses heat rate data from many plants which serve a particular load increment.

In a sense, the incremental heat rate method and the most sophisticated production costing model use the same basic approach in deriving their estimates of the system's short-run marginal running costs. Typically, the incremental heat rate method will use much fewer load level intervals than the hourly loads used by most production costing models. Still, by increasing the number of load level intervals used in applying the incremental heat rate method, its resulting avoided energy cost estimates can be made as precise as the user wishes at the cost of a greater computational burden on the user. In practice, the average incremental heat rate methods yield results which are more precise than the single unit approach and can be made more accurate by increasing the number of load intervals used.

The most sophisticated approach for estimating the marginal running costs of a utility system is the use of a production costing model. Such a model simulates the optimal (i.e., least-cost) system dispatch of generating units throughout the utility system under specified load conditions. The information required for this type of model includes the forecasted hourly load of the utility throughout the year, the expected hourly output from qualifying facilities, the operating cost characteristics of each of the utility's generation units and other data on fuel prices and power purchases.

The system lambda of the utility's last unit brought on line in an hour measures the marginal operating cost of the system during that hour. The hourly system lambdas input to or generated by the production costing model can serve as the basis for developing marginal avoided running costs based upon the timing of the expected delivery of power from qualifying facilities.

Feasibility of the Short-Run Marginal Cost Approach

The various short-run marginal costing methods are generally quite feasible and practicable approaches to estimating avoided costs. Information required in the calculations is available to commissions in most instances. Such information includes operating and maintenance and fuel cost data, and data on the output of the plant. This information is routinely collected by utilities, and while commissions may rely on the utilities to provide these data, if the commission thought it necessary, audits could be conducted to verify submissions.

In addition, most short-run marginal costing approaches are feasible, the necessary calculations are computationally simple, and thus, can be readily replicated and verified by commissions. This is true for the single unit method and its variations and the incremental heat rate method. However, the production costing method, on the other hand, does involve more complex calculations which may not be replicated as readily by commissions. Various production cost simulation models exist and if the commission employs a different model from the model used by the utility, discrepancies in estimates may result. The principal drawback of the production costing methods is that there may be no reliable data available on the amount and timing of generation by qualifying facilities over the next few years. Furthermore, a commission may be limited in its use of the production costing method by its available resources in terms of computer access, personnel and financial capabilities. Production costing methods require computer facilities and attendent personnel, and thus, these resources must also be available and affordable to the commission.

Generally, though, short-run marginal costing methods are relatively feasible approaches, particularly with respect to data availability and verification. Thus, for commissions with limited resources, most short-run marginal costing approaches provide an attractive and practicable choice for avoided cost estimation in situations where there is no avoidable capacity over the utility's planning horizon.

Compliance with FERC Rules

The use of the short-run marginal cost methods would comply with the FERC rules whenever the utility has no present or planned capacity that is avoidable because of the purchase of power from the qualifying facility. These situations include one in which a utility has suspended any new generation plant construction.

Also, no capacity might be available if the qualifying facility provides power on a non-firm (as available) basis. The existence or nonexistence and length of term of any contract between the utility and qualifying facility would be particularly relevant in deciding whether power would be available on a firm or non-firm basis. If the qualifying facility can only provide power during off-peak periods and if no additional base load capacity is planned, then, again, there might be no capacity avoidable due to purchases of power from qualifying facilities.

Non-generating utilities may not be able to avoid capacity if there is a long-term contract to purchase capacity from a wholesale company; however, they could possibly change their mix of firm and non-firm purchases and avoid some capacity portion of firm purchase rates. In addition, state public service commissions cannot require a wholesale company to pay a qualifying facility for avoided capacity due to purchases made by the non-generating utility, because the wholesale sale is subject to FERC jurisdiction, not state.

The Purchased Power Approach

The cost of purchased power is often suggested and is widely used as a means for estimating the avoided cost to the utility of purchasing power from qualifying facilities. Presumably, when a utility purchases power from qualifying facilities, it will be able to avoid making similar purchases from other utilities.

Purchased power costs can be used as a means of estimating both the short- and long-run avoided costs associated with the output from cogenerators and small power producers. Avoided running costs in the short run are typically considered equivalent to the energy charge (in ¢/kWh) of the utility's purchased power contract. Long-run avoided capacity costs are typically assumed to be equal to the capacity charges paid by the utility for its purchased power.

The purchase power approach has the advantage of being easy to implement without great expense, and thus the method is very practical. The method might reflect the cost savings to the utility of purchasing power from qualifying facilities when a utility purchases a large portion of its power in wholesale transactions.

The chief problem associated with using purchased power costs as a proxy for avoided costs is that the inter-utility systemwide avoided costs may not be the same as the costs avoided by the purchasing utility. For example, the purchasing utility's wholesale supplier may have excess capacity. Even if the purchasing utility is paying a capacity charge for wholesale power, no actual new capacity additions will be avoided if the purchasing utility substitutes power from qualifying facilities for power normally purchased from its wholesale supplier. The purchasing utility may avoid the payment of a capacity charge to its wholesale supplier but, if the wholesale supplier plans no new construction, then none can be avoided. Hence, the inter-utility systemwide avoided cost of capacity is zero, but since marginal cost pricing is not used in setting the wholesale purchase rate, a non-zero capacity charge to the purchasing utility distorts its own estimates of capacity costs.

Another example of the distinction between avoided cost based on purchased power and the actual cost savings realized by the purchasing utility is the case of a utility which has a long-term purchase contract calling for fixed capacity payments to its wholesale supplier. When this utility buys power from qualifying facilities and reduces purchases from its wholesale supplier, the purchasing utility will not avoid any capacity payment to its wholesale supplier, since these capacity payments have been predetermined and are enforced under a contractual obligation. The avoided capacity costs are entirely captured by the wholesale supplier who benefits from the reduced load of the purchasing utility. To argue that qualifying facilities should receive no avoided capacity payments because the purchasing utility realizes no capacity savings ignores the systemwide cost savings realized by the wholesale supplier.[13]

Another difficulty arises when the rates used for power pool transactions are adopted for use as avoided cost estimates. The greater efficiency made possible by power pooling and the centralized dispatch of generation units results in energy cost savings which may be split among both net exporting and net importing utilities.

If qualifying facilities are to capture the full avoided cost effect they have on a power pool, the right of a qualifying facility to capture the avoided cost it produces must supersede the split-the-savings approach of the power pooling agreement. Hence, sales by a qualifying facility to a net exporting utility should receive not only the savings share made possible by the greater net exports of this utility but also the savings made available to the importing utilities. Sales to a net importing

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[13]It is assumed in this illustration that the wholesale supplier has no excess capacity.

utility by qualifying facilities would result in the deduction of lost power pool saving shares (per kWh) of both importing and exporting utilities from the base level energy rate per kWh to be received by qualifying facilities. This adjusts the base level power pool kWh charge to reflect the reduced power pool generation efficiency due to fewer transactions within the pool.

In general, the use of purchased power to estimate avoided costs will be more accurate as the purchase agreement more closely relates energy charges to the marginal generation costs of the system. Hence, power pooling agreements with built in adjustments to reflect each utility's contribution to systemwide generating efficiency are more promising as estimates of avoided cost than the fixed per kWh charge of a simple purchase contract.

Feasibility of the Purchased Power Approach

The purchase power approach is quite feasible. Purchase power agreements are readily available from the utilities. All wholesale purchase power agreements are also on file with the Federal Energy Regulatory Commission. No elaborate calculations are usually needed, since energy and capacity charges can be taken right from the power purchase agreement with, at most, a small adjustment made to reflect avoided line losses.

Compliance with FERC Rules

Using the cost of purchased power as a means of estimating avoided costs would be in compliance with the FERC rules. In fact, PURPA Section 210 uses "the cost" to the electric utility of electric energy, which, but for the purchase "from the qualifying facility," the "utility would. . . purchase from another source," as a definition of the "incremental cost of alternative power."

The FERC rules [§§292.302, 292.304(e)] require that avoided costs be based on systemwide data. Thus the FERC rules require that avoided costs ought to be calculated systemwide when utilities are centrally dispatched. The FERC rules, however, are silent on how to treat a qualifying facility when a "split-the-difference" approach is used during power pool transactions regarding whether the qualifying facility should receive the savings shares of both the importing and exporting utilities as its avoided costs. However, in an earlier staff paper, FERC seemed to indicate that they intended that "if a pool has coordinated planning for capacity additions, the pool's method of sharing these costs should be considered, and in some cases utilized, in determining a pool member's avoided capacity costs."[14] FERC appears to give states great "flexibility for experimentation and accommodation of special circumstances"[15] in these situations.

The Reverse-the-Meter Approach

The reverse-the-meter approach allows qualifying facilities to receive a purchase rate equal to the selling rate that the utility charges the qualifying facility for electricity sold at the same voltage level. Hence, a new metering device may not be necessary, since purchases from the qualifying facility will cause its kWh meter to run backward. If kWh purchases exceed sales, the qualifying facility will receive a credit payment per kWh of net purchases by the utility less the usual utility fixed monthly customer charge.

One justification for using this approach is that its sheer simplicity may allow the utility to avoid installing a new, more costly metering device to gauge the output of the qualifying facility. When the potential sales from a qualifying facility are quite small, the additional metering costs associated with separately measuring the purchases and sales by qualifying facilities may be prohibitively expensive. Hence, when

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[14] 44 FR 38870

[15] 45 FR 12226

extremely low outputs from small power producers are involved, the reverse-the-meter pricing approach may avoid the imposition of intolerably burdensome new metering costs on these producers, and thus encourage their participation.

This method makes little pretense of attempting to estimate the utility's avoided cost. The average-cost base price at which the most utilities sell electricity is quite different from the marginal cost of generating the last kWh, since the last kilowatt-hours will be produced by the least efficient plant the utility has in use. Reverse-the-meter pricing would systematically pay less than a utility's avoided cost for power purchased from cogenerators and small power producers.

Feasibility of the Reverse-the-Meter Approach

While there are some theoretical shortcomings to reversing the meter as a means of ascertaining avoided costs, it nonetheless is a highly feasible approach. Reversing the meter is relatively easy to implement and involves little, if any, administrative costs. Further, reversing the meter does not require computer capabilities or complex calculations and models. For these reasons, reversing the meter may present an attractive alternative in situations where a qualifying facility is very small.

Compliance with FERC Rules

Reversing the meter, also known as "net energy billing," is addressed by the FERC in its comments to the rules. The FERC states that the net billing method may be an appropriate way of approximating avoided cost in some circumstances. The use of a "net energy billing" is specifically endorsed by the FERC as likely to be appropriate when retail rates are marginal-cost based, time-of-day rates.

It is less clear whether the FERC rules allow the reverse-the-meter approach when the use of a meter is not cost effective for extremely small qualifying facilities. It seems likely that the FERC rules would allow the reverse-the-meter approach in these circumstances, because FERC stated its comments that its intent was to encourage cogeneration and small power production.

The reverse-the-meter approach is unlikely to be in compliance with the FERC rules, except in the limited circumstances noted above. In other circumstances, a reverse-the-meter approach would tend to result in an average or embedded cost based purchase rate, not avoided cost.

The Differential Revenue Requirements Approach

This method of estimating avoided costs is based on the premise that the purchase of power from qualifying facilities should not affect the rates paid by other customer classes. Hence, payments to qualifying facilities are based on the avoided revenue requirement made possible by the utility's purchases from qualifying facilities.

The differential revenue requirement method uses load forecasts with an expansion planning model to develop expansion plans both with and without the estimated output of qualifying facilities. The resulting two expansion plans are then used as inputs for two runs of a utility financial planning model which yields the utility's projected revenue requirement both with and without the existence of purchases from qualifying facilities. The difference in the present value revenue requirements of these two expansion plans is the avoided revenue requirement made possible by the expected output from qualifying facilities. This avoided revenue requirement would encompass both projected avoided energy and capacity costs as well as other factors.

One potential difficulty with some of the versions of the differential revenue requirement method is that they do not attempt to measure avoided costs directly but rather measure avoided costs only insofar as they affect the utility's revenue requirement. The danger is that factors which are unrelated to actual avoided costs may influence the calculation. For example, if the allowed return on the rate base (or equity) is lower than the cost of raising new funds, the differential revenue requirement may systematically underestimate the avoided capacity costs made possible by purchases from qualifying facilities. A utility which finances much of its new investment through retained earnings will have an allowed return on new investment which may be significantly lower than the required rate of return on funds acquired in the open market. Hence, an inadequate return on shareholders' new investment in the form of retained earnings also implies that the qualifying facilities will receive lower avoided capacity payments based upon this below market estimate of the cost of financing new investment. In a sense, some versions of the differential revenue requirement method allow the conflicting interests of utility shareholders and consumers to spill over into the estimation of avoided costs.

Feasibility of the Differential Revenue Requirements Approach

The differential revenue requirements approach[16] provides a means of representing the utility's avoided costs as the difference between the utility's revenue requirements[17] with and without qualifying facilities. Data and modeling requirements are similar to those of the idealized method. To determine annual revenue requirements, the use of sophisticated generation expansion and corporate financial planning models, such as the Regulatory Analysis Model (RAm), is required. A number of assumptions, projections, and other factors affecting annual revenue requirements are involved in the use of these models. While some of these projections are filed under the requirements of Sections 133 and 210 of PURPA, others are not. Thus, the data needed as input to the revenue requirements approach

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[16]1980 Task Force on Cogeneration in Texas, Draft Report, Austin, Texas, pp. 22-24.

[17]Where revenue requirements are defined as total costs of meeting a specified demand plus a rate of return.

may be limited in availability. Further, the method may not be able to be used by utilities which lack the modeling capability, i.e., computer facilities, programs, and personnel. Similarly, qualifying facilities lacking in such modeling capabilities may find it difficult to verify independently the results of the method.

One important input to the differential revenue requirements method is a market analysis of the total amount of energy that is expected to be supplied by qualifying facilities within the utility's service area. While a market analysis can be undertaken with relative ease by the utility, the results may not be readily available to a commission, particularly for non-firm supplies, as this information is not required to be filed under the provision of PURPA Section 210.

In sum, the feasibility of the differential revenue requirements approach is limited by virtue of its reliance on data which may be of limited availability to the regulatory commission. This method is further limited in its applicability to only those with the modeling capacity, as is the idealized method.

Compliance with FERC Rules

The differential revenue requirements approach would also be a valid approach under the FERC rules to the extent that it reasonably accounts for a utility's avoided costs, and provides cogenerators and small power producers encouragement. At the same time, this approach would not adversely affect the revenue requirements, and hence rates. It can be argued that a method that results in unchanged revenue requirements is just and reasonable to the electric consumer of the electric utility and in the public interest. Thus, the differential revenue requirements approach would probably be in compliance with the FERC rules.

Simplified Average Incremental Cost Method

This approach can be used to produce rough approximations of avoided capacity and energy costs based on PURPA Section 210 data. The computations can be performed on a hand calculator.

The annual avoided capacity cost is found using several steps. First, find information on the expected additions to installed capacity in MW and their cost per kW expressed in constant (e.g., 1981) dollars for each year in the planning horizon. An example of this type of data appears in the second and third columns of table 5-5. The annual additions to installed capacity multiplied by the cost per MW (i.e., cost per kW x 1,000) yields the annual total capacity cost associated with capacity additions made in that year. These total costs of annual additions to capacity are shown in the last column of table 5-5.

TABLE 5-5

CAPACITY COSTS USING THE AVERAGE INCREMENTAL COST METHOD

Year	Annual Additions to Capacity (MW)	Capacity Cost (1981 constant dollars/kW)	Total Cost of Annual Additions to Capacity($)
1982	100	400	40,000,000
1983	500	800	400,000,000
1984	300	700	210,000,000
1985	600	1,800	1,080,000,000
1986	400	800	320,000,000
1987	300	900	270,000,000
1988	300	900	270,000,000
1989	300	900	270,000,000
1990	300	900	270,000,000
Totals	3,100		$3,130,000,000

Source: Hypothetical data from an illustration presented in 1980 Task Force on Cogeneration in Texas, Draft Report, (Austin, Texas), p. 25.

The total avoided capacity cost per kW is estimated by dividing the sum of the total cost of the annual additions to capacity over the planning horizon ($3,130,000,000) by the sum of the annual additions to capacity over the planning horizon expressed in kilowatts (3,100 MW x 1,000 = 3,100,000 kW). The preceding division results in a total cost per kW of new capacity of $1,009.68 i.e., $\frac{\$3,130,000,000}{3,100,000}$. This total cost of new capacity per kilowatt is then annualized by multiplying it by a carrying charge which reflects the utility's cost of funds, depreciation, taxes, and fixed operating and maintenance costs. A carrying charge of 22% would result in an estimated annual capacity cost of $222/kW (i.e., $1,009.68 x 22%). This estimate could then be converted to a monthly avoided cost capacity credit of $18.50/kW/month.

The average incremental cost method can also be used to estimate avoided energy costs. The energy cost per kilowatt-hour of electricity from the new additions to capacity each year is multiplied by the estimated annual kWh output of the new capacity installed each year to yield an estimate of the annual energy cost associated with each year's new capacity. An illustration of these energy costs is provided in table 5-6. Note that the megawatt-hours of output for each addition to capacity is estimated by assuming a capacity factor of .8 and multiplying this times the product of the annual additions to capacity in megawatts and the number of hours in a year.

The expected cost per kilowatt-hour of producing energy using the additional generation capacity to be installed over the planning horizon is found by dividing the total annual estimated energy cost of operating all of the generation plants installed over the planning horizon (e.g., $311,500,000) by the kilowatt-hour output of these plants (i.e., 21,700,000 MWH x 1,000 = 21,700,000,000 kWh). The illustration above yields an energy cost in 1981 dollars of 1.435 /kWh.

If the generation potential for qualifying facilities is small in a particular state, the costs to the commission of using a more analytical

TABLE 5-6

ENERGY COSTS USING THE AVERAGE INCREMENTAL COST METHOD

Year	Annual Additions to Capacity (MW)	Expected MWH from Annual Additions to Capacity (MWH)	Energy Cost of Additions to Capacity (1981 constant $/kWh)	Estimated Annual Energy Cost of New Capacity($)
1982	100	700,000	4.00	28,000,000
1983	500	3,500,000	1.50	52,500,000
1984	300	2,100,000	1.50	31,500,000
1985	600	4,200,000	0.75	31,500,000
1986	400	2,800,000	1.50	42,000,000
1987	300	2,100,000	1.50	31,500,000
1988	300	2,100,000	1.50	31,500,000
1989	300	2,100,000	1.50	31,500,000
1990	300	2,100,000	1.50	31,500,000
Totals	3,100	21,700,000		$311,500,000

Source: Hypothetical data from an illustration presented in 1980 Task Force on Cogeneration in Texas, Draft Report, (Austin, Texas), p. 25.

approach requiring computer facilities might outweigh the potential benefits of additional accuracy that might be achieved by the more analytical approach. In such a situation, a simplified approach, such as this one, might be both more practical and more feasible.

The imperfections of the average incremental cost method from a theoretical standpoint are significant. One deficiency is that it partially ignores the time value of money by failing to discount expenditure flows. A dollar spent in 1990 on a plant is worth less than a dollar spent in 1982, given that the 1982 dollar has the opportunity to earn interest over the intervening period. Since the energy and capacity costs are expressed in 1981 constant dollars, these cost flows should be discounted using a real rate of interest. The failure to discount annual additions to capacity and their associated annual energy cost produces an overestimate of avoided costs. Fortunately, this problem can easily be corrected by applying a real discount rate to the constant dollar cash flows used in making the estimates.

A second deficiency of the average incremental method is that it produces an estimate of the average capacity and energy costs on new generation facilities over the planning horizon. It does not provide an estimate of avoided costs based on the specific effect that purchases from qualifying facilities may have on the final mix of generation facilities constructed. Hence, this method assumes that the avoided capacity and energy costs can be based on the average costs associated with new capacity, when in fact avoided costs depend upon the specific future generation plants that may be eliminated or deferred through purchases from qualifying facilities.

A third difficulty of the average incremental cost method is that the carrying charge used to annualize the incremental capacity costs will often be a rough estimate due to the complexity of adjusting this charge to properly reflect tax and depreciation factors.

In summary, the average incremental method can produce a rough estimate of avoided costs which, in spite of its limitations, may be quite useful due to the relative ease of making the necessary calculations. A rough estimate of long-run avoided capacity costs may be useful as a standard to compare with more elaborate long-run avoided cost estimates generated by models whose complexity may mask major errors.

Feasibility of the Simplified Average Incremental Cost Method

Average incremental cost methods provide a relatively feasible means of estimating avoided costs. It does not require sophisticated models, computer facilities, and extensive data banks; the average incremental cost methods can provide fairly reasonable estimates of avoided costs without such inputs.

Average incremental cost methods rely on estimated energy and capacity costs filed under PURPA Section 210. These methods also use information on utilities' base expansion plans and long-range projected energy costs which must be filed with commissions in fulfillment of PURPA Section 133 and

Section 210 requirements.[18] In terms of data availability, then, the average incremental cost methods are predictable from a commission point of view.

One factor limiting the feasibility of the simplified average incremental cost method, though, is the calculation of the carrying charge. To calculate the carrying charge, the cost of capital, depreciation rates, and tax laws must be considered. Specialized finance personnel and specific data related to tax laws and depreciation rules are necessary to obtain accurate estimates. Commissions without these resources, though, may rely on rough estimates of carrying charges to enter into avoided cost calculations.

Because the average incremental cost methods do not require computer facilities and personnel or sophisticated modeling, they are also feasible with respect to cost constraints. In fact, when using the simplified average incremental cost method, avoided costs can be calculated with the use of a hand calculator in a relatively short time period. Thus, for utilities and commissions with limited resources, such methods provide an attractive and practicable alternative in the estimation of avoided costs.

As previously mentioned, results of the average incremental cost methods can also be used as a standard to compare with results of other more analytical methods, thus providing commissions with a relatively simple and inexpensive means of verifying utilities' avoided cost submissions.

Compliance with FERC Rules

The simplified average incremental cost method attempts to reasonably account for the utility's avoided costs and provides the encouragement of cogeneration and small power production required by the rules. Therefore, the method would probably be considered in compliance with the FERC rules.

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[18] 1980 Task Force on Cogeneration in Texas, Draft Report, (Austin, Texas) p. 24.

CHAPTER 6

SUMMARY

There exists a wide diversity of methods of calculating avoided costs. The idealized method of calculating avoided costs presented in chapter 3 is based on marginal costing concepts. Of the methods presented, the idealized method is intended to capture best the marginal nature of incremental and avoided costs. The idealized method also has the virtue of reflecting adjustments to the purchasing utility's expansion plan that are attributable to purchases from qualifying facilities. The cost of avoided capacity is linked to changes in the operating costs experienced by the utility. These costs of avoided capacity are allocated to purchase periods that reflect the probability that the purchasing utility might experience a demand that exceeds its available capacity. With the idealized method, the payment of the costs of avoided capacity reflects the duration of a capacity commitment, i.e., the greater cost savings of a longer commitment. Further, the idealized method also rewards the commitment of capacity by a qualifying facility during a utility's system emergency so as to reflect the costs of avoided reserve capacity. Also, the idealized method calculates avoided running costs that reflect the hourly variation in system lambdas experienced by the utility or the power pool.

However, as noted in chapter 4, the idealized method based on marginal costing concepts may not fully meet some possible needs of commissions. Strict adherence to the idealized method based on marginal costing concepts could increase slightly the utility's revenue requirements, and hence ratepayers' rates.

A solution to this problem would be to use a method which leaves revenue requirements unchanged. Chapter 4 includes calculations that would result in unchanged revenue requirements when the marginal cost approach is used. Chapter 5 describes several practical approaches to calculating avoided costs. One of the methods, which would leave revenue requirements unchanged, is the differential revenue requirement approach.

The idealized method, the differential revenue requirement approach, and some other methods noted in chapter 5 require the use of load forecast and capacity expansion planning models to develop expansion plans both with and without the estimated output of qualifying facilities. Some approaches also require the use of production cost simulation or financial planning models. For some state public service commissions, these methods may be infeasible because of a lack of computer facilities, the need for computer programs, or the difficulties associated with data collection and verification.

In addition, these more analytical approaches, in general, might not be practical for some commissions because the costs of using the methods might outweigh the benefits of using the methods. The potential benefits of using a more analytical approach might be limited by the potential for errors in forecasting. If the expected generation of qualifying facilities is small in a particular state, the costs of using a sophisticated approach may outweigh the potential benefits of the approach. In such a situation, a simpler approach might be both practical and feasible.

An example of a simplified approach that could produce a useful rough estimate of avoided costs, without great costs, is the simplified average incremental cost method. Any drawbacks of this method are related to the method's simplicity. For example, the method, as described in chapter 5, does not reoptimize the present capacity plan.

Another simple approach involves the use of the cost of purchased power as a means of estimating avoided costs. The purchase power approach is very feasible and may reflect the cost savings to the utility of purchasing power from qualifying facilities when a utility purchases a large portion of its power in wholesale transactions.

However, if the state public service commission decides to implement a more analytical method of calculating avoided costs, they might consider whether the method has the salient aspects of the avoided costs calculation methods, developed in chapters 3 and 4. These aspects are as follows:

1. Revenue requirements do not increase as a result of purchasing power at avoided cost;

2. Avoided capacity costs reflect adjustment to the utility's expansion plan that are attributable to purchases from qualifying facilities;

3. Adjustments to the utility's normalized load curve are based on potential commitments of capacity on a firm and non-firm basis;

4. Potential commitments of capacity by qualifying facilities regardless of the size of the commitment are aggregated for purposes of adjusting the normalized load curve;

5. The cost of avoided capacity reflects the change in the utility's income tax and property tax liability;

6. The cost of avoided capacity are linked to changes in the operating costs experienced by the utility;

7. The payment of the costs of avoided capacity to qualifying facilities reflects the probability that the utility might experience demand that exceeds its available capacity;

8. The payment of the costs of avoided capacity to the qualifying facilities can legitimately reflect the duration of a capacity commitment that results in the greatest cost savings;

9. The commitment of capacity by a qualifying facility during a utility's system emergency is rewarded and that reward should reflect the cost of avoided reserve capacity; and,

10. Avoided running costs reflect the hourly variation in system lambdas experienced by the utility or the pool.

Whichever approach to calculating avoided costs is chosen by a state public service commission, the state public service commission might consider setting purchase rates so as to signal to qualifying facilities that firm commitments of capacity result in greater cost savings than non-firm commitments of capacity. The purchase rates might also signal that longer term commitments of capacity have a greater value than intermediate- or short-term commitments. Also, the purchase rates might reflect that a commitment of capacity during system emergencies generates a cost savings. Purchase rates should signal to qualifying facilities that energy generated on-peak creates a greater savings than energy produced off-peak.

APPENDIX A

PURPA SECTIONS 201 AND 210 AND THE FERC RULES

PURPA Sections 201 and 210

Prior to the enactment of Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), sales from cogenerators and small power producers to a public utility might make the cogenerator or small power producer a public utility subject to the regulation of the Federal Energy Regulatory Commission (FERC). This would happen if the cogenerator's or small power producer's sale was a sale for resale in interstate commerce, i.e., if the electricity it sold might make its way into the bulk power transmission grid. This prospect of federal regulation tended to act as a disincentive to the generation and sale of surplus power by cogenerators and small power producers. In Sections 201 and 210 of PURPA, Congress dealt with the disincentive to electric generation imposed by the provisions of the Federal Power Act and with allegations that some utilities were not dealing in good faith with cogenerators and small power producers.

The scheme of PURPA Sections 201 and 210 is to provide certain substantial benefits in PURPA Section 210 to those cogenerators and small power producers who qualify as "qualifying facilities" as defined by PURPA Section 201 and the associated FERC rules.

PURPA Section 201--Qualifying Facilities

Section 201 of PURPA generally defines a "qualifying small power production facility," "qualifying small power producer," "qualifying cogeneration facility," and "qualifying cogenerator." Section 201 also empowers the FERC to establish detailed criteria for qualifying facilities by rulemaking. According to Section 201, a qualifying small power production facility is a site that has a combined capacity not greater than 80 megawatts and that together can only use biomass, waste, or renewable resources (including hydroelectric power from existing dams) as a primary energy source.

PURPA Section 201 defines a "cogeneration facility" as a facility which produces both electricity and steam or some other useful form of energy, such as heat, which is used for industrial, commercial, heating or cooling purposes. Qualifying small power production facilities and qualifying cogeneration facilities cannot be owned by a person primarily engaged in the generation or sale of electric power, other than power solely from cogeneration or small power facilities.

PURPA Section 210--Cogeneration and Small Power Production Rules

Cogenerators and small producers qualifying as "qualifying facilities" under PURPA Section 201 are entitled to the benefits of PURPA Section 210. One benefit is that electric utilities (defined as any person, state agency or federal agency which sells electricity) can be compelled to purchase power from qualifying facilities. The price for the purchases must be just and reasonable to the customers of the purchasing utility and in the public interest. FERC may not prescribe a price for these purchases which exceeds the incremental cost to the utility of alternative electric energy. In other words, the price for these purchases from qualifying cogenerators or small power producers can not exceed the cost of the electric energy to the electric utility which, but for the purchase from the qualifying cogenerator or small power producer, the utility would generate or purchase from another source.

A second benefit of being a qualifying facility under PURPA Section 201 is that PURPA Section 210 provides that utilities can be compelled to sell electricity to qualifying facilities. The price of the sale of electicity by the utility must be just and reasonable, in the public interest, and must not discriminate against the qualifying cogenerator or small power producer.

There is a third benefit of being a qualifying facility. Under PURPA Section 210, FERC can exempt all qualifying cogeneration facilities whose size does not exceed 30 megawatts of capacity from all or part of the

Federal Power Act, from the Public Utility Holding Company Act of 1935, and from state laws and regulations respecting the financial or organizational regulation of public utilities.

FERC Rules Implementing PURPA Sections 201 and 210

PURPA Section 201 requires FERC to issue rules and regulation defining the criteria and procedures by which small power producers and cogeneration facilities can obtain qualifying facility status in order to receive the benefits of PURPA Section 210. PURPA Section 210 directs FERC to establish rules and regulations requiring electric utilities to purchase electric power from and to sell electric power to qualifying facilities, as well as providing for the exemption of qualifying facilities from certain state and federal regulations. FERC issued its regulations pertaining to PURPA Sections 210 and 201 in final form in February and March of 1980, respectively. The substance of those rules is described below.[1]

The Qualifying Facility Requirements

Under the FERC regulations pertaining to PURPA Section 201, a "cogeneration facility" is a facility where the equipment is used to produce electric energy and forms of useful thermal energy for industrial, commercial, heating or cooling purposes, through the sequential use of energy. To be a qualifying facility under PURPA, cogeneration facilities installed beginning on or after March 13, 1980, must meet certain operating and efficiency standards (PURPA §201, Reg. §292.205). No efficiency standards are required for cogeneration facilities if installation began prior to March 13, 1980.

Under the FERC regulations pertaining to PURPA Section 201, a "small power production facility" is a facility that uses biomass, waste, or

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[1]Much of the discussion below is based upon the final rules promulgated by FERC and issued in the Federal Register at 45 FR 12214-37 and 45 FR 17959-17976.

renewable resources to produce electric power. To qualify as a qualifying facility, a small power production facility must have a capacity not exceeding 80 megawatts and must get more than 75% of its total energy input from biomass, waste, or renewable resources. The facility's use of oil, coal, or natural gas may not exceed 25% of the total annual energy input to the facility.

In addition, to be a qualifying facility, both cogeneration and small power production facilities may not have greater than 50% ownership by electric utility interests. At the time this report was written, Substitute Senate Bill 1885 was before the Subcommittee on Energy Regulation of the Senate Committee on Energy and Natural Resources. The bill would repeal the utility ownership limitation as to cogenerators. The bill would also authorize state public service commissions to establish restrictions on participation for both qualifying cogeneration and small power production facilities.

In order to become a "qualifying facility" and receive the benefits of PURPA Section 210, a cogeneration or small power production facility that meets the requirements listed above must be certified. There are two means by which a prospective qualifying facility can become certified. One means is a "self-certification." This process entails a qualifying facility that thinks it meets the PURPA Section 201 requirements certifying itself and notifying FERC of the following information: the name and address of the applicant and location of the facility; a brief description of the facility including a statement indicating whether the facility is a small power production or cogeneration facility; the primary energy source used or to be used by the facility; the power production capacity of the facility; and the percentage of ownership of any electric utility or by any public utility holding company, or by any person owned by either.

The second means by which a prospective qualifying facility can become certified is a more formal certification process. The facility may file for FERC certification as a qualifying facility. The application for certification must have the same information as the report of self-certification as well as additional information. Formal applications for certification must include a copy of a notice of the request for FERC certification for publication in the Federal Register. FERC must issue an order granting or denying the application for certification within 90 days, or else the application is considered to have been granted.

West Virginia has several potential cogenerators. Most chemical plants, coal mines, and paper mills are potential cogenerators. In addition, the Potomac Edison and Monongahela Power Companies have each reported that they serve an existing cogenerator.

Setting Rates for Purchases by Utilities

Once a qualifying facility is certified, it is eligible for the benefits of PURPA Section 210. One obligation of a utility under the FERC regulations implementing PURPA Section 210 is the obligation to purchase any energy and capacity which is available from a qualifying facility, except during certain operational circumstances addressed in PURPA §210, Reg. §292.304(f).

The FERC regulations require that rates for purchases be just and reasonable to the electric consumer of the electric utility, in the public interest, and non-discriminatory against qualifying cogeneration and small power production facilities. The rates for purchases from qualifying facilities are presumed to be just and reasonable, in the public interest, and non-discriminatory if they are set at the utilities' avoided costs, after the consideration of several factors affecting avoided costs, for any purchase from (new) capacity of a qualifying facility that construction commenced on or after November 9, 1978.

Purchases of power from capacity of a qualifying facility for which construction commenced before November 9, 1978, need not be set at avoided costs if the rates for purchase are just and reasonable to the electric consumer of the electric utility, in the public interest, non-discriminaory, and sufficient to encourage cogeneration and small power production.

The FERC regulations also state that nothing in the regulations requires any electric utility to pay more than the avoided costs for purchases.

The FERC regulations also require that standard rates be put into effect for purchases from qualifying facilities with design capacity of 100 kW or less. There may also be standard rates for purchases from qualifying facilities with a design capacity of over 100 kW. The standard rates for purchases are to be consistent with the requirements of rates for purchases from new capacity of a qualifying facility. As such, the rates would tend to be based on fully avoided costs, after taking into consideration certain factors. In addition, the standard rates may differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

The regulations require factors affecting the relationship between the availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods and the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use, to be taken into consideration when determining avoided costs. These factors include: the ability of the utility to dispatch the qualifying facility; the expected or demonstrated reliability of the qualifying facility; the terms of any contract, including the duration of the obligation, the termination notice requirement and sanctions for non-compliance, the extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities; the usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation; the individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and the smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities. The regulations also require that the costs or saving resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility be taken into consideration in determining avoided costs, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

The avoided costs paid for purchases from qualifying facilities can be based upon estimates of avoided costs over the specified term of a contract or other enforceable legal obligation. Thus rates for purchases can differ from the avoided costs at the time of delivery.

As noted above, the regulations state that purchases from qualifying facilities are not required during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make the purchases, but instead generated an equivalent amount of energy itself. An example of such an operational circumstance would be if a purchase from a qualifying facility, during a period of light loading, would force a utility to cut back output from a base load unit. Then these base load units might not be able to increase their generation rapidly when system demand later increased. The utility would then be required to utilize less efficient, higher cost units with a faster start-up to meet the demand that would have been supplied by the less expensive base load unit. Thus, the result of the transaction would be that rather than avoiding costs as a result of the purchase from a qualifying facility, the utility would incur greater costs. To avoid this result, the utility is not required to purchase from the qualifying facility during operational circumstances which would lead to the utility having higher costs because of the purchase from the qualifying facility.

The FERC rules concerning rates for purchases from qualifying facilities has been successfully challenged in the United States Court of Appeals for the District of Columbia (see American Electric Power Co. v. FERC, No. 80-1789, slip op. (D.C. Cir. 1982)). The case remanded the avoided cost rules back to FERC. The court held that by requiring the utilities to pay qualifying facilities fully avoided costs without fully justifying and explaining the decision to prohibit in an across-the-board manner rates below full avoided costs, FERC violated Section 210(b) of PURPA. PURPA Section 210(b) provides that any rates paid by the utilities to qualifying facilities "shall be just and reasonable to the electric consumers. . .and in the public interest." The court stated that

> "on remand we expect the commission to take a harder look, at, especially the percentage of avoided cost approach. Such an approach might, for example, entail FERC setting a specific percentage, or FERC might permit state commissions to set rates within a range--e.g., 80%-100%--authorized by the commission."

At the time of the writing of this report, these FERC rules are still in effect. The FERC has obtained a stay of the implementation of the decision, noted above, so that the government can decide whether to seek to appeal the decision. The present deadline for initiating the writ for certiorari is July 5, 1982, although the deadline can be extended for 60 days. Also, Substitute Senate Bill 1885 would specify that qualifying facility purchase rates must be equal to the utility's avoided costs. It would also ensure that states are permitted to balance the varied interests of their ratepayers against the goal of encouraging production by qualifying facilities. Regardless of whether or not the present FERC rules remain in effect, it seems likely that purchase rates will continue to be based on calculations of avoided costs.

Rates for Sales by Utilities to Qualifying Facilities

Another benefit to qualifying facilities under Section 210 of PURPA is that electric utilities are obligated to sell to qualifying facilities any energy and capacity requested by the qualifying facility. The FERC regulations require that the rates for sales be just and reasonable, in the public interest, and non-discriminatory against any qualifying facility in comparison to rates for sales to other customers. According to the FERC rules, rates for sales which are based on accurate data and consistent system wide costing principles are not discriminatory against any qualifying facility to the extent that the rates also apply to the utility's other customers with similar load or other cost-related characteristics.

In addition to services normally available to all customers, the FERC regulations require that each electric utility provide to its qualifying facilities upon request supplementary power, back-up power, maintenance power, and interruptible power. However, the state commission may waive the requirement that the utility provide its qualifying facilities these additional services if, after notice and public comment, the state commission finds that providing these additional services to the qualifying facilities will either impair the electric utility's ability to render adequate service to its customers or place an undue burden on the electric utility.

The FERC regulations also require that rates for sales of back-up power or maintenance power will not be based on an assumption that reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, unless supported by factual data. The FERC regulations also require that the rates take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

The Obligation to Interconnect and Interconnection Costs

The third major benefit to qualifying facilities granted by the FERC regulations promulgated under Section 210 of PURPA is that electric utilities are obligated to interconnect with qualifying facilities as may be necessary to accomplish purchases from or sales to the qualifying facility. However, this regulation has been successfully challenged in a case before the District of Columbia Court of Appeals. The court held that the FERC regulations that utilities must interconnect with cogenerators violated provisions of the Federal Power Act, which holds that FERC must give notice and hold a hearing before ordering each interconnection. The Federal Power Act requires that interconnection not unduly impair utility reliability. Presently, the FERC rules are still in effect, while FERC appeals the issue to the United States Supreme Court.

These qualifying facilities and also all qualifying small power production facilities producing electric energy solely by the use of biomass as a primary energy source, even if it has a power production capacity of over 30 megawatts, are exempt from the provisions of the Public Utility Holding Company Act of 1935 and certain state laws and regulations, respecting regulation of the rates of electric utilities and financial and organizational regulation of electric utilities. All qualifying facilities are still subject to state law and regulation that implement PURPA Section 210.

APPENDIX B

SURVEY OF STATE PROCEEDINGS: DATA AND DOCUMENTS

Proceedings of state public service commissions, relative to the calculation of avoided costs, were surveyed through information gathered under the Regulatory Information Exchange Project.[1] A summary of the survey data and the document citations of the documents obtained in the survey are presented in this appendix.

The following table summarizes commission proceedings. Thirteen commissions have issued final orders relative to Section 210 of the Public Utilities Regulatory Policies Act of 1978. Twenty-five commissions have issued interim orders. Thus, a total of thirty-eight state commissions have issued orders on the calculation of avoided costs.

In nine of these states, the commissions approved rates for specific utilities for the energy component of avoided costs. Six commissions approved rates for both the capacity component and the energy component. Orders from fourteen states specified a method or mathematical formula to be used in the calculation of the energy component of avoided cost rates; while twelve states specified a methodology or formula to be used in the calculation of both the capacity component and the energy component.

Following the summary table, citations of the documents obtained in the survey are listed. (Descriptions of the methodologies used by several of these states are presented in chapter 2 of this report.) Copies of the documents listed can be obtained by calling the contact persons of states. The contact persons are identified in the most recent Current Awareness Bulletin of the National Regulatory Research Institute.

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[1]Administered by The National Regulatory Research Institute. The survey contains information received by the Regulatory Information Exchange Project as of April 30, 1982.

TABLE B-1

SUMMARY OF STATE PUBLIC SERVICE COMMISSION PROCEEDINGS ON THE CALCULATION OF AVOIDED COSTS

State	Section 210 Orders[1]		Commission Approved Rates for Specific Utilities		Order Specifies Method/Formula for Calculating Avoided Costs	
	Final	Interim	Energy	Capacity	Energy	Capacity
Alabama		x	No	No	No	No
Alaska		x	No	No	No	No
Arizona		x	No	No	No	No
Arkansas						
California						
Colorado		x	No	No	No	No
Connecticut		x	No	No	No	No
Delaware	x		Yes	No	Yes	No
District of Columbia		x	No	No	No	No
Florida						
Georgia		x	No	No	No	No
Hawaii						
Idaho	x		Yes	Yes	Yes	Yes
Illinois		x	No	No	No	No
Indiana		x	No	No	No	No
Iowa	x		No	No	Yes	Yes
Kansas		x	No	No	No	No
Kentucky		x	No	No	No	No
Louisiana		x	No	No	No	No
Maine						
Maryland		x	Yes	No	No	No
Massachusetts	x		No	No	Yes	Yes
Michigan		x	No	No	No	No
Minnesota						
Mississippi		x	No	No	No	No
Missouri	x		No	No	Yes	Yes
Montana	x		Yes	Yes	Yes	Yes
Nebraska						
Nevada						
New Hampshire		x	No	No	No	No
New Jersey	x		No	No	Yes	Yes
New Mexico	x		No	No	No	No
New York		x	No	No	No	No
North Carolina	x		Yes	Yes	Yes	Yes
North Dakota	x		No	No	No	No
Ohio		x	No	No	No	No
Oklahoma		x	No	No	Yes	Yes
Oregon		x	Yes	Yes	Yes	Yes
Pennsylvania		x	No	No	No	No
Puerto Rico						
Rhode Island	x		No	No	Yes	Yes
South Carolina		x	No	No	No	No
South Dakota						
Tennessee						
Texas		x	No	No	Yes	Yes
Utah	x		Yes	Yes	No	No
Vermont		x	Yes	Yes	Yes	Yes
Virginia	x		Yes	No	Yes	
Virgin Islands						
Washington		x	No	No	No	No
West Virginia						
Wisconsin						
Wyoming						
Number of States 38	13	25	9	6	14	12

[1]Received by Regulatory Information Exchange Project as of April 30, 1982. (Other orders may have been issued by state commissions which have not been forwarded to the Project.)

Source: Regulatory Information Exchange Project. Prepared by Amy Garant, The National Regulatory Research Institute.

State Commission: By State	Documents By Citation
Arkansas	In the Matter of the Determination of the Rules Regulating the Rates and Service of Congeneration and Small Power Producers, Docket No. 81-071-F, Order No. 3
California	Recommended Commission Policies and Price Rules for Utility Purchases of Cogenerated, Auxiliary and Small Production Facility Power, Order Instituting Investigation No. 26, Exhibit No. 41.
Connecticut	Application of the United Illuminating Company to Increase Its Rates, Supplemental Decision II, Docket No. 800601.
Idaho	In the Matter of Rulemaking Proceedings as Required by the Public Utility Regulatory Policies Act of 1978 for the Consideration of Cogeneration and Small Power Production, Case No. P-300-12, Order No. 16025.
Iowa	In Re: Iowa State Commerce Commission Rules Regarding Rates for Cogeneration and Small Power Production, Docket No. RMU-80-15, Order Issued March 20, 1981.
Kansas	Order on Cogeneration and Small Power Production, Docket No. 115,379-U
Massachusetts	Regulations, D.P.U. 535
Montana	In the Matter of Avoided Cost Based Rates for Public Utility Purchases from Qualifying Cogenerators and Small Power Producers, Docket No. 81.2.15, Order No. 4865a.
New Jersey	In the Matter of the Consideration and Determination of Cogeneration and Small Power Production Standards Pursuant to the Public Utility Regulatory Policies Act of 1978, Decision and Order--Docket No. 8010-68.
North Carolina	E-100, Sub. 41, September 21, 1981
Oklahoma	Cause No. 27208, Order No. 186937, March 26, 1981

State Commission: By State	Documents By Citation
Oregon	In the Matter of the Investigation into Electric Utility Tariffs for Cogeneration and Small Power Production Facilities, Order No. 81-319.
Rhode Island	In Re: Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities, Docket No. 1549.
Texas	Final Report of the 1980 Task Force on Cogeneration in Texas.
Utah	In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in the State of Utah, Report and Order, Case No. 80-999-06.
Virginia	Ex Parte in re: Implementation of Federal Rules concerning Cogeneration and Small Power Production Facilities pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978 for Virginia Electric and Power Company, Case No. PUE800102.

APPENDIX C

SOCIAL WELFARE, MARGINAL COSTS, AND AVOIDED COSTS

In the model presented here and discussed in chapter 3, the regultory and utility management are assumed to set prices and install capacity so that social welfare is maximized. The customary definition of welfare is used in which the sum of consumers' surplus and producer's surplus from the production of electricity is as large as possible. Prices that maximize social well-being in each pricing period can be found for the case in which the quantity of electricity produced is constrained by the utility's capacity. The prices that emerge from this restricted capacity model are easily related to the long-run equilibrium in which capacity is chosen optimally. A characteristic of this equilibrium is that neither consumers nor the utility can be made better off without making the other worse off. These prices are said to lead to allocative efficiency.[1] Regulatory authorities, however, might have other objective besides economic efficiency. Questions of equity, distributive justice, and other potential roles of ratemaking are unused in the discussion of ratemaking in chapter 4. The purpose of this appendix is to briefly develop a multi-period, possibly hour by hour, model of marginal cost and to show how these hourly marginal costs are related to the optimal, long-run capacity expansion program of the utility. This rather complicated description of marginal cost is important in the measurement of avoided costs in chapter 3. Such a measure can be useful to regulators even if their objectives are broader than the rather narrow focus on economic efficiency taken in this appendix.

This peak-load pricing model is based on a welfare function. Since an electric utility's demand varies according to a diurnal and seasonal pattern, n discrete time periods are assumed to exist in a demand cycle.

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[1]This is a condition in which the economy is producing that mix of goods that best satisfies consumers' wants given the prevailing distribution of income.

Furthermore, the demand in any given time period is assumed to be independent of all other time periods.[2] As a result, the price in period t depends only on the quantity demanded in that period.

The welfare function is based on the concept of consumers' and producer's surplus.[3] The objective is to maximize the sum of these two measures subject to a capacity constraint. The welfare function for the peak-load model is

$$W = \sum_{t}^{n} \int P_t(q_t)dq_t - \sum_{t}^{n} \int \frac{\partial C_t(q_t,K)}{\partial q_t} dq_t \qquad \text{(C.1)}$$

where

t - an index of n time periods

$P_t(\cdot)$ - the price in period t

q_t - the quantity in period t

$C_t(\cdot)$ - the variable costs in period t

K - installed capacity

The cost function underlying the specification for producer's surplus is

$$C = \sum_{t}^{n} C_t(q_t,K) + \bar{q}(K) \qquad \text{(C.2)}$$

where $\bar{q}(\cdot)$ is the fixed costs. The variable costs in period t depends on both output and installed capacity. The fixed cost $\bar{q}$ $(\cdot)$ depends only on the level of installed capacity.

The capacity contraint is relatively straightforward. It is

$$q_t - K \leq 0 \quad t = 1,\ldots,n \qquad \text{(C.3)}$$

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[2]Elimination of this assumption does not alter the conclusions of the model.

[3]This measure of welfare is not without problems. It assumes the distribution of income is fixed and the marginal utility of a dollar is the same for all individuals.

Output in period t is either less than or equal to installed capacity. Capacity (K) is measured in terms of units of output.

The objective function and the constraint are used to form the Langranian function[4]

$$\underset{q_t, K, \gamma_t}{\underset{\text{MAX}}{L}} = \sum_t^n \int P_t(q_t)\,dq_t - \sum_t^n \int \frac{\partial C_t(q_t,K)}{\partial q_t}\,dq_t - \sum_t^n \gamma_t(q_t - K) \qquad \text{(C.4)}$$

where γ_t is the Langranian multiplier[5] associated with the capacity constraint. The Langranian is maximized by using the Kuhn-Tucker conditions.[6] The solution yields the following on-peak and off-peak pricing prescriptions.

$$P_t = \frac{\partial C_t(q_t,K)}{\partial q_t} + \gamma_t \quad \text{on-peak} \qquad \text{(C.5)}$$

$$P_t = \frac{\partial C_t(q_t,K)}{\partial q_t} \quad \text{off-peak} \qquad \text{(C.6)}$$

The first term on the right hand side of both equations C.5 and C.6 is the marginal running cost experienced in period t. Thus, by equation C.6, the off-peak period price is based only on the marginal running costs. These costs are the change in the variable costs of operation for period t attributable to a change in output during that period.

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[4]The Langranian function is a mathematical tool used to solve for the value of variables that maximize or minimize a function subject to a constraint.

[5]The Langranian multiplier will take on the value necessary to achieve the maximum or minimum in periods that the capacity constraint is effective. In this case, γ_t is called the shadow price of capacity.

[6]Kuhn-Tucker conditions are used when an inequality constraint is present.

The on-peak period's price is based on the marginal running costs plus a rationing cost, γ_t. The Langranian multiplier is positive when the quantity demanded exceeds the capacity of the system. Its role is to ration scarce capacity during periods of high demand by increasing until the quantity demanded is equated to available capacity. Thus, the on-peak price is based on a cost consisting of an energy component and a capacity component. The energy portion is the marginal running costs experienced in period t. The capacity portion rations scarce capacity.

The capacity portion of the marginal costs incurred during the on-peak period is related to the level of capacity installed in a long-run equilibrium. It is easy to show that the optimal level of capacity is installed when

$$\sum_t^n \gamma_t = \sum_t^n \frac{\partial C_t(q_t,K)}{\partial K} + \frac{\partial \overline{q}(K)}{\partial K} \qquad \text{(C.7)}$$

The condition is equation C.7 states that the sum of the rationing costs for all time periods equals the cost of marginal capacity. This marginal cost consists of two elements. The first expression on the right hand side of equation C.7 is the change in running costs attributable to changing the capacity of the system. The second expression is the change in the fixed costs attributable to changing capacity. When the rationing costs (γ_t) sum to the cost of marginal capacity, the utility has installed the level of capacity necessary to maximize welfare over the entire demand cycle when charging prices given by equations C.5 and C.6.

In summary, the maximization of a welfare function subject to a capacity constraint when a single supplier confronts a multiple-time period demand function yields an equilibrium set of prices. The price for each time period is equal to the marginal running costs plus a capacity rationing cost. This rationing cost is a positive amount when the quantity demanded is less than capacity. The sum of these rationing costs over the entire demand cycle is the value society places on marginal capacity.

Capacity is optimal when these rationing costs equal the change in the fixed cost attributable to varying capaity plus the sum of changes in the running costs for each time period attributable to adjusting capacity. In practical terms, this means a demand of 1 Kwh for 8760 hours will recover the annual addition to the cost of capacity per unit of added capacity plus the marginal running costs associated with the 8760 kWh produced. These marginal costs can be computed for each hour of the year. In turn, these can be averaged over the hours of each pricing period. Such a measure of peak period marginal cost is an important and consistent way of defining avoided cost in chapter 3.