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ORIGINAL

Decision No. 92749 March 3, 1981

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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| Investigation on the Commission's own motion into a methodology for the calculation of marginal costs of electric service. | OII No. 67 (Filed April 2, 1980) |

Robert Ohlbach, Daniel E. Gibson, Kermit R. Kubitz, and Merek E. Lipson, Attorneys at Law, for Pacific Gas and Electric Company; John R. Bury and Richard K. Durant, by Robert W. Kendall, Attorney at Law, for Southern California Edison Company; and Steve Edwards, Attorney at Law, for San Diego Gas & Electric Company; respondents.

John C. Lakeland, for Mass-Production; Arlene Nizenski, Attorney at Law, for Eugene Coyle; Robert E. Burt, for California Manufacturers Association; Boris H. Lakusta, David J. Marchant, and Thomas J. MacBride, Attorneys at Law, for California Hotel and Motel Association; Donald G. Salow, for Sacramento Municipal Utility District; John P. Terry, for City of Los Angeles, Department of Water and Power; Reed V. Schmidt, for himself; and McNees, Wallace & Nurick, by H. R. MacNicholas, Attorney at Law, for California Industrial Energy Consumers; interested parties.

Sara S. Myers, Attorney at Law, for the Commission staff.

# O P I N I O N

## Introduction

In this proceeding we seek to implement a general methodology for calculating the marginal costs for electric utilities. Such a methodology is necessary since legislative and administrative regulations and requirements on both the state and federal levels now provide for, and in some cases require, the consideration and use of marginal cost data in electric utility rate proceedings. Our adopted methodology is contained in Appendix B.

Marginal cost may be defined as the change in total cost which results from a change in output. The result of using marginal cost in ratesetting is that the rate equals the cost of producing one more unit, or the savings from producing one less unit. Since no customer underpays or overpays for consumption, conservation and efficient use of resources is encouraged and equity is achieved.

Marginal costs calculated under the adopted methodology will have a variety of applications. First, they will be filed in rate proceedings and may be used as the basis of our rate designs. Second, they will be filed with the Federal Energy Regulatory Commission (FERC) in accordance with Section 133 of PURPA. Third, marginal costs developed through a Commission-approved methodology will be used in rates as required by the California Energy Commission's (CEC) load management tariff standard. Fourth, these costs will relate to the utilities' cogeneration price offerings as defined under the FERC regulations governing Section 210 of PURPA. Fifth, the utilities' marginal costs will be used to evaluate the cost-effectiveness of load management and conservation programs and to design the tariffs or incentives applicable to such programs. Sixth, and finally, the knowledge of these utility costs should greatly assist us in examining utility resource options including nongeneration alternatives.

Our staff and that of the CEC, in cooperation with the utilities and many consumer groups, have been researching the methodologies for calculating marginal cost. The existing methodologies were presented, examined, applied to each utility, and evaluated by the participants in this study. It was determined that the existing methodologies were not sufficiently applicable to California's utilities because of the diversity of resource mix. Consequently, the staffs of the two commissions developed a general framework for marginal cost calculations to be used in California.

Following a long series of meetings between the staffs of the two commissions, the utilities, and the interested parties, copies of a staff-recommended methodology were provided to all interested parties and electric utilities in California by letter of the Executive Director dated November 20, 1979. On April 2, 1980 we instituted this investigation (OII 67) as a means of providing a formal forum for considering the staff's proposed methodology and to adopt a methodology for consideration in general rate proceedings. A number of utilities and interested parties filed written comments on the staff's proposal; requests for hearings were also made. These written comments were summarized, responded to by the staff, and distributed to all interested parties with the issuance of OII 67. Following distribution of the staff's response to the comments, a hearing was held before Administrative Law Judge (ALJ) Bertram Patrick on May 12, 1980. The hearing was duly noticed and attended by respondent electric utilities and parties representing various electric utility consumer interests. Parties unable to attend were given the opportunity to file written comments on the staff's response.

Rule-making Procedure

The objective of calculating marginal costs is very simple. The objective is to measure the additional cost to provide an additional unit of electricity or the cost saved from serving one unit electricity less. The problems that arise in the measurement, however, present many complications.

Since marginal cost calculation for electric utilities is still in a developmental stage, it is apparent that all we could hope to accomplish at this stage is to set forth a general methodology to provide a conceptual base against which we can evaluate marginal cost data presented in future Commission proceedings.

Because of the technical nature of the subject, the Commission, at the staff's recommendation, decided that a rule-making procedure would be most appropriate. We did not hold evidentiary hearings in the usual sense because our purpose was to adopt guidelines and filing requirements for electric utilities. We did and do not intend to cast with finality a method that will be directly used in ratesetting. Rather, we are establishing a starting point to begin analyzing marginal cost data.

Procedural Objections of Toward Utility Rate Normalization (TURN)

TURN takes issue with the adopted hearing procedure.

It is TURN's position that the Commission is required by Public Utilities Code Section 1705 to include in its decisions findings of fact on all material issues. TURN states that such findings must be based on record evidence and that there is no evidence in the record of this proceeding. TURN believes that "comments" by the parties and proposals by the staff, untested by cross-examination, are simply not sufficient to support a Commission decision on contested issues. For these reasons, TURN requests that the Commission set aside submission to permit the presentation of evidence and cross-examination.

We are surprised by TURN's belated objection to the hearing procedure. All interested parties, including TURN, were notified of the hearing individually in writing five weeks in advance. The hearing procedure was set forth in OII 67 as follows:

> "To facilitate an exchange of views on this complex technical subject between our staff, the Energy Commission staff, the utilities and interested parties, the following procedures will be employed. A hearing will be held before Commissioner Richard D. Gravelle and/or Administrative Law Judge Bertram D. Patrick on May 12, 1980. At the hearing, parties will be given the opportunity to make oral comments on the contents of Appendix B, as well as other items deemed appropriate by the presiding officer. Sworn testimony and exhibits will not be utilized. In addition to the opportunity to discuss the Appendix B items, each party will be given the opportunity to make a closing statement." (Emphasis added.)

On receipt of the above notification, TURN did not renew its request for evidentiary hearings.[2] TURN informed the ALJ of its inability to attend the proceeding because of another commitment. TURN was then given the opportunity to file written comments.

In considering TURN's objection to the hearing procedure, we should bear in mind the history of this proceeding. The opening statement of staff counsel Sara S. Myers provides such a perspective:

> "Just so that we can put this proceeding in perspective, I know that most of the people here have probably been participants in either the Marginal Cost Pricing Project or are aware of the development of a marginal cost methodology over the last several years, but I do believe it's important for the record to reflect some of that activity.
>
> "Today's proceeding marks the culmination of several years of concerted effort by this state's regulatory agencies, electrical utilities and other interested parties to define and apply a uniform methodology by which marginal costs of electric service can be calculated.
>
> "This effort began in March, 1976, when the Commission in its investigation of electric utility rate structures first established the need and use for marginal cost data in studying electric rates.
>
> "That decision having been made, only the issue of the calculation of those costs remained for further study and development.
>
> "To accomplish this goal the Marginal Cost Pricing Project was formed in 1977.
>
> "The project was funded by the Department of Energy and jointly managed by this Commission and the Energy Commission.

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2/ In its comments dated December 21, 1979, TURN requested that evidentiary hearings be scheduled if the Commission determined that a single methodology for marginal cost pricing would be adopted.

"It has the stated purpose of developing during a three-year period a method for calculating marginal costs of electric service and implementing the marginal cost rates in California.

"During this operation the project has met frequently. Its participants and invitees have included not only this staff but representatives from the state's largest privately and publicly owned electric utilities as well as consumer and industry representatives and other interested parties.

"Participants not only heard representatives of each of the major marginal cost methodologies explain their position but the utilities had the opportunity to apply each of the methodologies to their operations.

"Simultaneously with and in certain instances even predating these meetings marginal cost data was being presented in rate cases.

"The data included in the standard requirement list for a utility's rate filing was the subject of both the utility and staff testimony and cross-examination.

"Following almost two years of study the staffs of the Energy Commission and the PUC presented a draft of a proposed methodology to Marginal Cost Pricing Project participants.

"This was done on August 17, 1979.

"The project met for comments on August 22 and written comments were received on September 10.

"In October a revised draft resulting from this input was mailed to project participants, who again met for comments later in the month.

"On November 20, 1979, /a revised/ draft was mailed by the Commission to approximately 250 parties.

"/On/ December /21/ parties responded and provided written comments.

> "These comments were studied and on April 2, 1980, OII 67, this proceeding, was issued. It appended the final marginal cost methodology proposed by this Commission's staff as well as the staff's summary and, you noted, response to the last set of comments.
>
> "With this hearing and the opportunity to comment which is afforded by it the staff believes that the Commission will have before it not only the results of an exhaustive study but all positions on marginal cost methodology as well."

In addition to the fact that this rulemaking was a joint cooperative effort between the staff, utilities, and interested parties, it is worthwhile noting that TURN was invited to join this effort by letter dated November 28, 1978 (Appendix A) but chose not to participate. Instead, TURN now chooses to raise objections.

The special hearing procedure to which TURN objects was adopted after careful consideration and notice to all parties. The Commission intended by this procedure to provide a hearing process which would not only comply with due process requirements but would also expedite Commission adoption of a marginal cost methodology. To this end, a rulemaking procedure, clearly justified by the nature and history of the proceeding, was ordered.

The methodology we adopt is not intended to stifle alternative approaches to calculating the marginal costs of electric utilities. As stated in OII 67 (page 2):

> "In keeping with these legislative and administrative mandates on both the state and federal levels, it is the Commission's intention to provide a general method for calculating the marginal costs of electric utilities and thereby to make such information available to all parties to our proceedings. We do not intend, however, to preclude the electric utilities or interested parties from presenting or recommending other data in our proceedings. . . ."

While the adopted methodology will be a mandatory requirement for applicant utilities in general rate increase proceedings, and other proceedings where deemed necessary, the utility and interested parties, including TURN, will not be precluded from advancing alternative marginal cost studies. Also, where the methodology adopted is not applicable to the utility's operation or resource plan, deviation from the mandatory requirement will be permitted to the extent necessary upon an appropriate showing.

The Commission, in this rulemaking proceeding, is performing a legislative and administrative function and is not making a final judicial determination affecting specific rights and liabilities of parties. No final determination is being made in this proceeding on the merits of a specific case or controversy.

Extensive evidentiary hearings in this proceeding would have been premature. The application of the many approaches to marginal cost determinations will be tested in utility ratesetting proceedings. Accordingly, we deny TURN's request for evidentiary hearings. At this stage TURN may have some constructive input (which was raised in its filed comments), but this is the wrong proceeding to hold exhaustive hearings. TURN will have its chance in later proceedings to propose alternate approaches and test those of others.

Mandatory Filing Requirements

At the present time, the Commission requires the filing of marginal cost data under its "Standard Requirement List of Documentation Supporting the Increase in an NOI". The Load Management Standards adopted by the Energy Commission include the requirement that marginal cost rates, developed through a method approved by a utility's rate-approving body, must be submitted with rate applications. (20 Cal Admin. Code, Ch. 2, Subch. 4, Art. 5, Sec. 1623.) Federal legislation (Section 115(a) of the Public Utility Regulatory Policies Act (PURPA) (16 USC Sec. 2625)) permits each state regulatory authority, in considering the implementation of the federal standard for cost of service, to prescribe the method for determining the costs of providing electric service to each class of electric consumer. The Federal Energy Regulatory Commission (FERC), pursuant to Section 210 of PURPA, has adopted regulations providing that prices paid for power purchased from qualifying cogenerators and small power producers will equal the full avoided (marginal) cost of the utility for such purchases. These regulations provide for the Commission to implement this pricing rule in California. Consequently, data based on the proposed methodology is already being considered in current electric utility rate proceedings, in developing avoided costs for power purchased from cogenerators and small power producers, and in testing the cost-effectiveness of conservation programs. In view of the several applications for marginal cost data, it is apparent that by setting forth a general methodology we can better evaluate marginal costs presented in Commission proceedings.

## COMMENTS OF PARTIES

We will now turn to a discussion of the comments made at the hearing and those submitted by parties unable to attend (TURN and Pacific Power & Light Company (PP&L)).

Verification by Intervenors

Arlene Nizenski, representing Eugene Coyle, consulting economist, believes that access should be provided to the utility's computer model; otherwise, consumer participation will be precluded because of prohibitive cost. According to her, access to the utility's data by itself is not sufficient.

We note that all electric utilities filing general rate increase applications with this Commission are required to disclose all data and the computer model used in preparing marginal cost studies. This is a mandatory requirement under our Notice of Intention (NOI) procedure for the filing of general rate increase applications. In addition, FERC regulations governing the reporting of marginal cost data under Section 133 of PURPA provide that sufficient data be made available for intervenors to verify the utility results.

Intervenors are entitled to make data requests of a utility in a rate proceeding. The utility can determine whether the request is reasonable or not and may reject excessively burdensome requests. If the intervenor believes the request is reasonable, the intervenor can request the Commission to order the utility to respond.

We believe sufficient protections and opportunities for verification and making data requests are now available without additional burdens being placed on the utility, and without the costs being unreasonably transferred from intervenors to the utility. Mr. Coyle's request is denied.

Definition of Marginal Cost

Robert E. Burt, appearing for California Manufacturers Association (CMA), believes that the base cost of the utility's original plan should be clearly set forth in its workpapers, so that the actual total cost and not only the change in cost can be calculated for the anticipated change in load.

We believe that CMA's request is reasonable. Accordingly, in Chapter 3 of the methodology, under Generation Costs on page 7, paragraph 4, we will add the following:

> G. The total costs of the utility's basic resource plan will be provided to enable determination of the change in total cost resulting from the anticipated total change in load.

Short-Run Marginal Costs

Robert W. Kendall, appearing for Southern California Edison Company, took exception to a statement in the staff response to comments of interested parties, under the subheading "Short-Run Marginal Costs" which reads:

> "We [the staff] agree that the appropriate price for electricity is the short-run marginal cost plus a charge sufficient to constrain demand to available capacity (i.e., the shortage cost or rationing charge)."

Mr. Kendall points out that the above statement is in conflict with paragraph 4, in Chapter 1 of the methodology (Appendix B), which states:

> "...no guidance is provided as to the proper or preferred manner for using marginal costs in either rate design or resource planning."

Edison is in agreement with the latter statement and requests that the prior statement be stricken because it could be quoted out of context in various proceedings.

Donald G. Salow, representing Sacramento Municipal Utility District (SMUD), supported Edison in its objection to staff's reference to pricing in this proceeding. SMUD would like it noted on the record that marginal cost as calculated using the methodology should not reflect a rationing cost, but the pricing is totally a separate issue.

This decision adopts a marginal cost methodology and does not adopt staff's comments to the comments of other parties. We agree with Edison and SMUD that the methodology provides no guidance as to the proper or preferred manner for using marginal costs in either rate design or resource planning.

Kilowatt and Kilowatt-hour Output

Edison, joined by California Industrial Energy Consumers, expressed concerns regarding paragraph 7, page 4, of the methodology (Appendix B), which states:

> "To measure a change in cost, a change in utility output must be specified. Utility costs change with respect to kilowatt demand, kilowatt-hour usage, and the number of customers on the system. Kilowatts and kilowatt-hours are dependent on each other. The cost of a kilowatt-hour is in part a function of the relative magnitude of the kilowatt associated with it (or vice versa, the cost of a kilowatt is determined by the number of hours it must be provided)."

Edison believes there is room for possible misuse of the above concept in rate design. It further believes that even though it is difficult to separate demand costs from energy costs, this needs to be done. It is Edison's position that it is necessary to recognize demand components as well as energy components in the costs that are being created by customers. In the absence of a demand charge, there no longer will be an incentive for large customers to monitor and limit their demands on the system at the time of the system peak. In order to clarify this point, Edison asks that the following sentence be added to paragraph 7 on page 4 of the methodology (Appendix B):

> "Demand costs can be identified through use of the scenario methodology and should be stated in dollars per kilowatt."

Staff responded to Edison's concerns by pointing out that the methodology at page 7, subparagraph 4.B, requires annualized cost of each resource change be reported, in both cents per kilowatt-hour and dollars per kilowatt. Staff points out that the methodology does not address rate design issues and only covers costing considerations. Accordingly, staff believes Edison's fears are unfounded.

We should point out that the adopted methodology is a general methodology and is a compromise between marginal cost advocates believing in an energy orientation and those believing in a demand orientation. The adopted methodology is flexible enough for Edison to present its case in future proceedings. We will not specify any particular orientation at this time, but only note that the methodology requires data representing both viewpoints.

Marginal Cost Method

Position of CMA

Robert E. Burt, appearing for CMA, believes that the the following statement at Chapter 3, paragraph 1, of the methodology, needs to be more explicit:

> "All costs will be calculated in a manner consistent with the costs used in other resource planning and evaluation studies."

Mr. Burt believes the discount rate should be established at a preliminary stage, so that all parties preparing studies may use the same rate. He pointed out that the resource planning and evaluation studies were very sensitive to the discount rate used. He believes everybody ought to be using the same rate, otherwise, people using the same data will come up with vastly different costs.

The utility is already required to provide this information under the proposed methodology, which uses the rules adopted by FERC to implement Section 133 of PURPA. We recognize Mr. Burt's concerns, but do not think the solution is to further burden the utility with data requirements.

In order to facilitate comparisons between marginal cost studies, all parties are encouraged to levelize costs using the same carrying charge rates (or discount future costs using the same discount rates) as the utility, where there is no substantial disagreement with the utility's estimate. If any party needs the utility's carrying charge rate or discount rates prior to their disclosure in the normal course of the utility's filing its data in compliance with Section 133 or its exhibits and work papers supporting an NOI to file a general rate increase request, the party should send a data request to the utility. Utilities should respond to such data requests as soon as possible.

Position of Pacific Gas & Electric Company

Stephen J. Metague of Pacific Gas & Electric Company requested that the word "linear" be stricken from the following sentence in Chapter 3, Section B - Transmission Costs, paragraph 6, of the methodology, which reads:

> ". . . A linear regression with cumulative peak demand increments as the independent variable and cumulative net additional transmission investment as the dependent variable will demonstrate the historical and projected relationship between transmission costs and demand. . . ." (Emphasis added.)

Mr. Metague points out that deletion of the word "linear" may be particularly useful in the future when the costs of building facilities as a function of load may not all exhibit the same pattern. He believes the methodology should be flexible enough to accommodate change. We agree, the word "linear" will be deleted.

Other Issues Raised by SMUD

Donald G. Salow, representing SMUD, suggested the methodology be changed in the calculation of demand-related distribution and customer costs. We believe the proposed methodology captures the appropriate costs. Furthermore, the methodology does not prohibit the presentation of other approaches. Should they wish, parties in rate proceedings may present data and costs such as those recommended by SMUD.

Mr. Salow pointed out that SMUD does not have the ability to calculate and present loss of load probability (LOLP) or excess load probability (ELP) data as required in Chapter 3, Section G. However, we do not believe the methodology should be modified as suggested by SMUD. SMUD is not regulated by this Commission. It may pursue its points before the Energy Commission.

Comments of PP&L

PP&L believes that the proposed methodology is not applicable to it in certain areas because of its unique resource constraints. We do not believe the proposed methodology should be modified to accommodate PP&L and we will recognize PP&L as being a special case. Accordingly, PP&L is encouraged to continue to work with our staff to develop the specific areas in which an alternative approach is warranted. PP&L will be allowed to use an alternative methodology where the adopted methodology is inappropriate. PP&L should include such data and supporting reasons for the alternative approach when it files data pursuant to Section 133 of PURPA and when it tenders an NOI to file a general rate increase application.

Comments of TURN

TURN's comments generally promote the shortage cost concept, which is a method of measuring the cost of electricity not being available or, in the alternative, the cost necessary to reduce demand in times of short supply. We recognize that shortage cost is a valid concept and TURN may pursue this further in subsequent proceedings. We do not believe that at this time any change should be made in the proposed methodology to reflect this concept. We again note page 2 of OII 67 states:

> ". . . We do not intend, however, to preclude the electric utilities or interested parties from presenting or recommending other data in our proceedings. . . ."

TURN may present any data it thinks is relevant, including shortage cost data, in subsequent rate proceedings.

Findings of Fact

1. Marginal cost data is being considered in current electric utility rate proceedings, in developing avoided costs for power purchased from cogenerators and small power producers, and in testing the cost-effectiveness of conservation programs.

2. A general methodology for the calculation of marginal costs is necessary for use in proceedings before this Commission.

Conclusions of Law

1. The Commission may and should establish a general methodology for utilities to follow in calculating their marginal cost of electricity in rate proceedings.

2. The adopted methodology should not be the final statement on calculating marginal costs.

3. All electric utilities should furnish marginal cost studies based on the adopted methodology as part of their mandatory presentation in all general rate increase proceedings. This should not preclude the utility or any interested party from presenting alternate studies that do not conform to the adopted methodology.

4. Where a particular requirement of the adopted methodology is not applicable to an electric utility, the utility should be granted a deviation from filing information on the particular requirement upon a showing that the requirement is not applicable to the utility's operations or resource plan.

5. The adopted methodology will not provide guidance as to the proper or preferred manner for using marginal cost or rationing cost in either rate design or resource planning. Only costing considerations are addressed in the adopted methodology.

6. The adopted methodology will not provide guidance as to the proper or preferred manner for using demand costs.

7. The methodology for calculating marginal costs for electric utilities, attached as Appendix B, is reasonable and should be adopted.

8. The effective date of the following order should be the date of signature so California utilities can begin to prepare filings on the basis prescribed by the adopted methodology.

<u>O R D E R</u>

IT IS ORDERED that the methodology for calculating marginal cost for electric utilities, attached as Appendix B, is adopted.

The effective date of this order is the date hereof.

Dated MAR 3 1981, at San Francisco, California.

John E. Bryson
President
Richard D. Gravelle
Leonard M. Grimes, Jr.
Victor Calvo

Commissioners

APPENDIX A

STATE OF CALIFORNIA—THE RESOURCES AGENCY

EDMUND G. BROWN JR., Governor

ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSION
1111 HOWE AVENUE
SACRAMENTO, CALIFORNIA 95825

(916) 920-6145

November 28, 1978

Ms. Silvia Siegel
Executive Director
Toward Utility Rate Normalization
693 Mission Street
San Francisco, California 94103

Dear Ms. Siegel:

As you are aware, the Energy Commission and Public Utilities Commission have endorsed marginal cost-based pricing for electricity. In support of these policies the CEC and CPUC are sponsoring the Marginal Cost Pricing Project which involves the five major California utilities and seven trade associations and public interest groups. You are invited to join this cooperative effort that will have a major impact on rates in California.

The objective of the MCPP, which began in October 1977, is to develop a method to quantify the marginal costs of electric service and design marginal cost-based rates. The first year research investigated marginal cost methods. The second year, just getting underway, will develop rates based on marginal costs.

Funds may be available to pay for attendence at meetings (about once every six weeks) and reimburse for expenses. To advise us of your interest and to obtain more information please contact John Wilson.

John A. Wilson

JOHN A. WILSON
California Energy Commission
MCPP Coordinator

Burton W. Mattson

BURTON W. MATTSON
Public Utilities Commission
MCPP Coordinator

cc: Burton W. Mattson

OII 67/ALJ/ks

APPENDIX B

A METHODOLOGY FOR CALCULATING MARGINAL COSTS

FOR ELECTRIC UTILITIES

ADOPTED BY

CALIFORNIA PUBLIC UTILITIES COMMISSION

OII 67 /ALJ/ks

APPENDIX B

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APPENDIX D

# CHAPTER 1

## INTRODUCTION

1. This paper presents a general method for calculating the marginal costs of an electric utility. It provides guidelines for the calculation of the marginal costs of utilities making cost presentations before the Public Utilities Commission and Energy Commission. The paper sets forth a general model with allowances for refinements designed to lead to a closer approximation of marginal costs.

2. The methodology is not intended to be the final statement on calculating marginal costs. It should serve as a foundation from which additional research can proceed. Several components of this method could, and hopefully will, be improved with further study. However, it is clear that sufficient knowledge now exists to make reasonable, usable estimates of marginal costs. As additional knowledge becomes available and better procedures are developed, the methodology will be revised accordingly.

3. The primary concern is ensuring that the method used to calculate marginal costs does in fact measure the change in total cost for a given change in output. While the mechanics of the calculations must be demonstrably valid, they are of less concern than the concepts behind them. Any set of computations, whether manual or computerized, must be evaluated against the conceptual base presented here and compliance with this foundation demonstrated.

4. The purpose of calculating marginal cost is to determine the cost of the resources which are used in the production of increments or decrements of electricity. One can use this information in rate design, as well as resource and conservation evaluation, to improve the efficiency with which resources are used. A costing methodology must be sufficiently precise to yield results which can be used to provide accurate price signals and valid cost comparisons. The framework presented will allow the calculation of marginal costs which are general in application. That is, no guidance is provided as to the proper or preferred manner for using marginal costs in either rate design or resource planning. Only the costing considerations are addressed in this paper.

## 1 - INTRODUCTION

5. This methodology uses the data requirements specified in the Federal Energy Regulatory Commission (FERC) regulations governing the collection of data under Section 133 of the Public Utility Regulatory Policies Act of 1978 (PURPA). With additions and revisions as specified herein, the biennial filing to FERC should provide sufficient data for the calculation of marginal cost.

6. Chapter 2 defines marginal cost, discusses characteristics of electricity production and presents the conceptual approach to be used. Chapter 3 details the marginal cost method. Chapter 4 lists data requirements of this methodology beyond those specified by FERC for Section 133 implementation.

CHAPTER 2

MARGINAL COSTS FOR ELECTRIC UTILITIES

1. The development of a method to quantify the marginal costs of electric service requires a definition of marginal cost that relates the general economic definition to the characteristics of electricity supply. This chapter presents a practical definition of marginal cost that can be used to evaluate alternative methods of estimating utility marginal costs.

A - DEFINITION OF MARGINAL COST

2. Marginal cost is the change in total costs of production caused by a change in output. Total production costs increase with output along a given total cost curve. If marginal costs are declining, additional increments of output are less expensive than previous increments. If marginal costs are increasing, additional increments of output are more expensive than previous increments.

3. Marginal costs can be distinguished as short or long run. That is, the production costs to meet a change in output are different given the ability of the producer to adjust the factors of production. In the short run plant is fixed and the producer can only run existing plant more or less, or buy or sell more or less electricity. The short run marginal cost is the change in the variable operating cost with respect to changes in output. In the long run the plant capacity can be adjusted to minimize the total costs of producing the new output requirement.

B - CHARACTERISTICS OF ELECTRICITY PRODUCTION

4. The basic relationship of cost and output that defines marginal cost is very elementary. Applying the concept, however, becomes complicated when it is necessary to determine which cost and which ouput to measure. Utility systems are very complex, comprised of investments and expenditures to provide generation, transmission, distribution, and service facilities. Electricity can be measured as the instantaneous level of output (kilowatts), or the volume of output (kilowatt-hours). Kilowatts and kilowatt-hours are not

independent since the cost of a kilowatt depends in part on the duration (hours) of the load. At a given moment neither an additional kilowatt nor kilowatt-hour can be produced without also changing the output of the other.

Short and Long Run Costs

5. A characteristic of utility costs is the difference between short and long run costs. Short run costs are the extra operation and maintenance expense of running existing facilities to meet additional load. Long run costs include the capital cost of expanding plant capacity, as well as reoptimizing plant mix to meet changes in variable input costs.

6. In an optimal system in long run equilibrium, short and long run marginal costs are equal. In practice, given fluctuating fuel costs and lumpiness of expanding capacity, a utility is likely to be over or under capacity, or have too much or too little of specific plant types. Long run marginal costs in this methodology are based on practical changes in the resource plan rather than on the costs of a completely optimal system. System marginal operating costs are estimated over a similar costing horizon.

Kilowatt and Kilowatt-Hour Output

7. To measure a change in cost, a change in utility output must be specified. Utility costs change with respect to kilowatt demand, kilowatt-hour usage, and the number of customers on the system. Kilowatts and kilowatt-hours are dependent on each other. The cost of a kilowatt-hour is in part a function of the relative magnitude of the kilowatt associated with it (or vice versa, the cost of a kilowatt is determined by the number of hours it must be provided).

8. Estimating marginal cost means estimating the change in total cost associated with a change in output. Since kilowatts and kilowatt-hours are dependent, the change in cost must be in response to changes in both output measures jointly (kilowatts and kilowatt-hours). Marginal costs should ultimately be calculated with a method that explicitly recognizes the link between the kilowatt magnitude of load and its duration.

## 2 - MARGINAL COSTS FOR ELECTRIC UTILITIES

### C - CONCEPTUAL APPROACH

9. The fundamental concept of marginal cost analysis is identification of the least cost system response to a change in demand. The source of this information is each utility's system planning department. The system planner will describe the changes which occur in the utility's resource plan if an increase or decrease in demand is explicitly recognized in the plan keeping system reliability constant.

10. The system response identified by the planner provides the basic level of information to allow the calculation of marginal costs. The change in total cost caused by the change in demand can be calculated based on the affected units, time frames, and/or operating characteristics. While the marginal costs which result from alternate scenarios may not precisely reflect all of the system's planning options, they provide a usable estimate of the utility's marginal cost.

11. Marginal cost can be calculated for various load changes. At the simplest level, the change in load is specified over the entire year and the resulting change in capacity cost is identified. An allocation procedure is then needed to estimate the portion of the annual marginal cost for which each time period is responsible. At a more complex level the change in load is specified and the resulting change in cost is identified separately for each time period (and independently of other time periods). In this latter case, the marginal cost of each time period is calculated directly (without the requirement of allocating annual costs to time periods). While both approaches will provide usable cost estimates, the preferred approach to the calculation of marginal costs is to directly perturb demands in each time period separately (independently of other time periods) and calculate the resulting per unit change in costs.

## CHAPTER 3

## MARGINAL COST METHOD

1. Marginal costs are the change in total costs that result from changing output. Marginal costs will be developed by calculating the change in the utility's total costs (operating expenses and investments) for specified increments or decrements in output. All capacity-related marginal costs (expenses and investments) will be expressed in both dollars per kilowatt, and cents per kilowatt-hour. All costs will be calculated in a manner consistent with the costs used in other resource planning and evaluation studies.

2. The preferred method of calculating the marginal capacity costs of generation, transmission and distribution is to analyze the change in costs resulting from changes in demand (output) in each time (costing) period separately. Annual marginal capacity costs with allocation or other methods as described below are acceptable if multiple scenario analysis is not possible.

### A - GENERATION COSTS

3. The load change will:

A. Be an increment or decrement in megawatt capacity to which planners and planning models can respond with reasonable results, and which will produce a change in the size or timing of generation resource alterations or the ability to offer sales.

B. Occur at the beginning of the period and continue for the duration of the costing horizon.

C. Be for either:

(i) Single scenario: A change for all hours of the year, or

(ii) Multiple scenario: Changes for each of the costing periods individually.

3 - MARGINAL COST METHOD

4. The utility will report:

A. The specific generation and generation-related transmission plants or purchases or sales affected (e.g., size, timing, operating characteristics).

B. Annualized cost of each resource change, in both cents per kilowatt-hour and dollars per kilowatt.

C. Cost and load forecast assumptions used, and resource planning models or procedures used.

D. Costs by voltage levels that account for line losses.

E. Fuel savings calculated by comparing total production costs before and after addition of the marginal units.

F. Cost estimates will include costs of all facilities necessary for environmental regulations including the cost of purchased offsets. These costs may be included in either the capacity or energy costs (whichever is appropriate and supportable).

G. The total costs of the utility's basic resource plan will be provided to enable determination of the change in total cost resulting from the anticipated total change in load.

B - TRANSMISSION COSTS

5. If the utility is able to identify the change in transmission costs directly by evaluating the costs of serving single or multiple load scenarios as described above, such costs should be provided.

6. Marginal transmission costs (exclusive where possible of generation-related transmission costs and costs of replacements) can also be calculated by examining the relationship between net investment in transmission facilities and growth in transmission system peak demand. A regression with cumulative peak demand increments as the independent variable and cumulative net additional transmission investment as the dependent variable will demonstrate the historical and projected relationship between transmission costs and demand. The marginal cost of transmission is estimated as the projected increase in transmission investment for each kilowatt increase in demand.

7. The time period to be examined in such a regression must be sufficiently long to overcome the inherent lumpiness of the data. A 15-year period of 10 years historical and 5 years projected data is prescribed.

## 3 - MARGINAL COST METHOD

### C - DISTRIBUTION

8. If the utility is able to identify the change in distribution costs directly by evaluating the costs of serving single or multiple load scenarios as described above, such costs shall be provided.

9. The utility's marginal distribution system can also be analyzed by its being segregated into the components which vary by the level of demand and those which are dependent on the number of customers on the system. An acceptable way of accomplishing this is to remove from the total projected distribution costs (net where possible of replacements and non-growth-related costs) the costs associated with adding the projected number of new customers to a minimum distribution system (e.g., 100 watts). The remainder represents the demand-related distribution costs. As with transmission costs, the cumulative additional distribution investments will be regressed against the cumulative additional distribution system peak demands over a relevant time period to determine the amount of distribution investment required for each kilowatt addition to peak demand.

### D - ENERGY COSTS

10. The marginal energy cost requirements of this methodology will be the same as those for Section 290.303 of the Federal Energy Regulatory Commission regulations implementing Section 133 of the Public Utility Regulatory Policies Act with two exceptions. First, paragraph (g) data will be provided for ten years. Second, paragraphs (g) and (h) calculated costs by costing periods will be weighted by either kilowatt-hours or hours.

### E - CUSTOMER COSTS

11. Marginal customer costs will be reported in two ways. First, as a hypothetical minimum distribution system (over the entire system) to provide the minimum service (e.g., 100 watts). A description of the equipment and associated installation expenses per customer shall be provided by voltage level. Second, the average annualized minimum system total per customer hook-up costs by voltage level for the test year shall be provided. In addition, customer expense information will be provided by voltage level.

## 3- MARGINAL COST METHOD

### F - COST ALLOCATION

12. Where a multiple scenario approach has been used, the capacity cost responsibility by costing period can be directly calculated. This is the preferred method for determining capacity costs. However, if a scenario analysis has not been performed for each costing period, it is necessary to allocate the capacity costs in order to assess the cost responsibility of each period.

13. The responsibility for generation, transmission, and distribution capacity costs can be correlated with the probability that increased load will exceed the available plant. The measurement of a utility's inability to meet load provides a measurement of the need to install additional capacity and the degree to which marginal capacity costs are incurred.

14. Loss of load probability (LOLP) or excess load probability (ELP) - when LOLP is unavailable - measures the probability that load on the utility's generating system will exceed the capacity of that system. Their relative values can be used as a measure of the inability to meet demand and, consequently, as a guide to allocate costs.

15. Transmission substation loading data may be an acceptable alternate to the use of generation-related LOLP or ELP for transmission cost allocation.

16. Distribution system demand patterns may be different from those on the generation and transmission system and, hence, LOLP or ELP may not reflect the need for new distribution capacity. Consequently, the allocation of distribution capacity costs should be based on a study of distribution system loads.

### G - COSTING PERIODS

17. Four methods are acceptable for use singly or in combination to determine the diurnal or seasonal periods of cost variation. Data will be filed on Methods A, B and C. Method D data may be substituted for that of Method C if LOLP data is not available.

## 3 - MARGINAL COST METHOD

18. The utility should justify the use of any one or combination of the four methods but must provide sufficient data to allow comparisons among the four.

A. Examination of Load Curves

Examination of the patterns of demand for relevant days and months over a period of several recorded and projected years provides a basis for the identification of periods of similar load (which should correlate with cost variation). The utility shall define the peak, shoulder and off-peak hours in reference to the system annual and seasonal peaks.

B. Projection of Marginal Energy Costs

Hourly energy costs shall be provided for typical days in each month of the reporting (test) year.

C. Loss of Load Probabilities

Loss of load probabilities will be used to define periods whereby hours of similar outage probabilities are grouped together. This requires that relative LOLP's be calculated for typical days in the reporting (test) year.

D. Excess Load Probability

Test year hourly loads will be analyzed to indicate the probability of each hourly load exceeding specified megawatt amount(s). Hours with similar probabilities of demand exceeding the specified limits will be grouped.

# CHAPTER 4

## ADDITIONAL DATA REQUIREMENTS

1. With the exceptions as noted below, the data described in Subparts C and D of the FERC regulations implementing Section 133 of PURPA are sufficient for the purposes of this methodology. Any marginal cost study should include this data requirement as well as the actual marginal cost calculations.

2. Additional data must also be presented as follows:

A. Information Supplementary to FERC Data Requirement

Sec. 290.302 Generation cost information.

(b) Production planning information for planned additions to generating capacity.

The planning horizon is extended as necessary to correspond to the planning period for generation plant changes.

The calculation of fuel and operating savings associated with the addition of the marginal plant(s).

The average annual system heat rates before and after the addition of each plant.

Sec. 290.303 Energy cost information.

(g) Marginal energy costs by costing period and by year.

For each year of the planning horizon (minimum of 10 years).

(g) & (h) Calculated marginal energy costs by costing period.

Single marginal energy costs calculated for each of the costing periods will be calculated by weighting each hourly marginal energy cost by the kilowatt-hours generated in that hour or the number of hours in the costing period. (Data to allow weighting by kilowatt-hours will be filed even if the reported marginal energy costs are weighted by hours.)

Sec. 290.304 Transmission cost information.

(a) Plant information.

(1) Expenditures for replacements must be separately reported to the extent possible. Also, any other non-growth-related transmission plant should be separated out if available.

4 - ADDITIONAL DATA REQUIREMENTS

(b) Operating and maintenance expense.

Expenses associated with non-growth-related plant must be separately reported if available.

Also:

(1) The annual peak on the transmission system for 10 years' historic and 5 years' projected.

Sec. 290.305 Distribution and customer cost information.

(a) Plant information.

(1) Non-growth-related plant additions must be separately reported if available.

Also:

(1) The annual peak on the distribution system for 10 years' recorded and 5 years' projected.

(2) The projected numbers of customers in each customer class, by voltage level.

(3) All components of a minimum system separately reported.

(b) Operating and maintenance expense.

Also:

(1) Percentage of total distribution operating and maintenance expense that is customer-related.

Sec. 290.306 Other cost information.

(a) Customer expenses.
(b) Sales expenses.
(c) Administrative and general expenses.

Reported by customer class or voltage level.

B. Other Information to be Reported

(1) Loss of load probabilities or excess load probabilities for each hour of typical days for each month of the test year.

(2) Loss of load probabilities or excess load probabilities grouped by costing periods.

(3) Distribution demand study