Setting Rates: Best Practices for Electric Cooperatives

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Embedded Cost of Service: An Overview of the Analysis

Introduction

This special Solutions News Bulletin insert is the fifth in an ongoing series, "Setting Rates: Best Practices for Electric Cooperatives." The series examines how electric cooperatives can apply best practices when setting rates for their members.

Embedded costs are the historical booked costs of plant in service as well as expenses. Their analysis, within the context of a cost-of-service analysis, has been, and continues to be, a fundamental tool for allocating costs to customers in a non-discriminatory and equitable way throughout the electric utility industry. Although marginal costs, unit formulary rates and market-based rates have emerged as viable alternatives to allocated embedded costs for various non-captive services, captive services are frequently subject to cost-of-service analysis. For electric cooperatives, cost of service is by far the predominant tool behind rate making, and most state regulatory commissions require cost-of-service studies in rate filings.

This article describes the workings of embedded cost-of-service analysis and discusses the strengths and weaknesses of the analysis.

Objective of Cost-of-Service Analysis

Cost-of-service studies have become one of the basic tools of ratemaking. While opinions vary about the most appropriate methods, few analysts seriously question that service—regardless of class—should be provided at cost. This "cost-based principle" has become applicable not only to the overall rate by class but also to individual components of the rate. Cost-of-service studies are, therefore, used for the following purposes:

- to attribute costs to different categories of customers based on how those customers cause costs to be incurred,
- to determine how costs will be recovered from customers within each customer class,
- to calculate the cost of individual types of service based on the costs each service requires,
- to separate costs between two (or more) jurisdictions and
- to measure the degree of rate discrimination present in rates.

Today, one of the most important uses of cost-of-service studies is to measure the degree of rate discrimination in existing or proposed rates. For example, large customers frequently take service at higher voltage levels. Additionally, they have different load characteristics. As customers take service at higher voltage levels, they use less of the distribution system. In fact, customers served at 69 kV and above use none of the distribution system. Therefore, it makes sense they should not be charged for investment in the system they are not using. For this reason, as well as the different load characteristics, cost-of-service models were developed that compute a revenue requirement and allocate that revenue requirement to the individual classes of service based on the class load characteristics. The overall objective is to equalize returns across classes, or equalize times interest earned ratio (TIER) requirements across classes.

The application of cost-of-service-based rates suggests rate discrimination is not present. However, cost-of-service rates are seldom, if ever, adopted. Therefore, in practice, the cost-of-service study provides a benchmark so the degree of rate discrimination can be objectively measured. Once measured, a subjective decision can be made about the degree of rate discrimination and whether it is unduly discriminatory.

Overview of Cost of Service

The primary objective of a cost-of-service study is to determine as precisely as possible what it costs the cooperative to provide electricity to a rate class or member over the course of a test year. The secondary objective is to determine how costs will be allocated to and recovered from each rate class. Cost-of-service studies also provide information about which rate classes are providing revenues in excess of their costs and which rate classes are providing revenues insufficient to cover their costs. These studies can be used as guides in designing retail rates that match revenues to costs and minimize rate discrimination.

Since the Rural Utilities Service system of accounts maintains books and records in the aggregate, there is no direct way to assign jointly used costs to individual rate classes. Accordingly, cost of service was created as a way to allocate these costs to the individual rate classes. Although cost-of-service studies have been in use for some time, and prominent organizations like the Federal Energy Regulatory Commission (FERC) and the National Association of Regulatory Utility Commissioners have issued recommendations, the process has certain constraints, including the lack of class load data, which serves as a basis for the allocation of significant plant costs; the significant time and money required to complete the study; and the fact that cooperatives operate in a constantly changing environment. Consequently, calculating precise costs can be difficult, and certain assumptions must be made and customers must be grouped by load characteristics or type of service to enable a practical and reasonably accurate study to be prepared.

For these reasons, it is important to understand that cost of service is not a perfect rate-making tool, and management must not rely exclusively or excessively on the results of the study when designing retail rates. Indeed, some economists would argue that embedded cost allocation is not an economically efficient basis to determine rates and that an analysis of marginal costs is superior. Although there is merit to this argument, utilities and regulatory commissions have gravitated to embedded or accounting costs as a basis for determining rates, which requires a method of cost allocation like a cost-of-service study. Because embedded cost studies are by far the most common type of study used by utilities and regulatory commissions, this article focuses on them.

Cost Causation

There is broad agreement that the investment in distribution plant is related to a utility's peak demand. The number of members and energy sales are also cost drivers. Everyone, however, does not employ the same methods for analyzing the various cost components, and there is a wide range of views on their nature (fixed, variable, joint, common, etc.) and on how they should be recovered in rates. Factors such as the number of customers, usage and demand are obvious, but population density, system design and business practices are also important factors. Although the implications of these issues on rate design are unclear, a cooperative can only charge for services on the basis of number of customers, usage and demand, not on the basis of other factors—despite the fact that these other cost factors can have a large effect on prices.

Classification of Costs

There are three major cost components in providing electricity to a customer:

- **Energy related:** These costs are simply the energy charges from the wholesale power provider.
- **Customer related:** These are costs that do not vary with the load but do vary depending on the number of customers, the cost of the service entrances, the cost of meters and the cost of billing and collection. Some utilities and regulatory commissions also include a portion of the primary and secondary distribution plant, believing they are driven more by the number of customers than by demand or energy. Similar reasoning leads to the inclusion of the expenses of customer service and installations on the customer's premises as being customer related. On the other hand, since the system is sized to serve a maximum level of anticipated demand, there is an argument that customer costs (with the possible exception of metering and billing) should be categorized as demand related.
- **Demand related:** Utilities classify significant portions of their distribution plant as demand related, reasoning that it is designed and built to serve a member or rate

class according to their contribution to peak load. Substations are a typical example of these costs, but so are a significant portion of the wires and related facilities since they are sized, at least in part, to serve a peak demand.

There are a number of methods for differentiating between the customer-related and demand-related cost-of-service components of distribution plant, including:

- the basic customer method,
- the minimum-size method and
- the zero-intercept method.

The basic customer method, which is the most common, classifies meters, meter reading and billing as customer related and all poles, wires and transformers as demand related.

The other two approaches assume there is a minimum-size distribution system that gives customers access but is incapable of serving any level of demand. The assumption is that since the minimum-size system cannot serve demand, it therefore must be customer related. Also, since the costs of this minimum-size system are driven by the number of customers, they are considered customer costs. The demand-related portion is the difference between total distribution costs and the customer-related costs.

All three approaches have the same basic problem—they rely on assumptions. In the basic customer method, it is the classifying of expenses into customer-, demand- and energy-related components that may or may not be reasonable. In the case of the minimum-size and zero-intercept methods, it is the assumption there is some portion of the distribution system that is unrelated to demand. Since these are the lowest costs that must be incurred before any amount of power can be delivered, these costs are deemed to be customer related.

After all the costs are grouped into the customer, demand and energy cost components, the costs must then be allocated to the individual rate classes.

Allocation of Costs

Generation- and transmission-related plant costs are typically allocated to electric cooperative consumer rate classes based on some measure of coincident peak (CP) demand, while distribution-related plant costs are allocated on non-coincident peak (NCP) demand. Differences emerge in the determination of allocators as to whether costs should be allocated on a single peak demand, seasonal average peak demand, a 12-month average peak demand, or on some balance between demand and energy such as average and excess.

Distribution facilities are generally designed and operated to serve localized area loads. Substations are designed to meet the maximum expected load of the lines radiating from them at the primary and secondary service levels. For costing purposes, it is the relevant substation's peak that matters, but these peaks may or may not be coincident with each other or with the overall system's peak. (In the short run, distribution costs vary more closely with number of customers than with load—except in capacity-constrained areas. For rate design, with its focus on the long run, this is not an issue. It does, however, have implications for setting revenue requirements.)

Consequently, one method is to allocate the costs of substations and primary feeders to customer class NCP and to allocate secondary feeders and line transformers to the individual customer's maximum demand. (Class NCP may not be the best measure of cost causation since much of the system serves a variety of customer classes. Ideally, the objective is to design rates that reflect the costs of customer contributions to the relevant peak.)

Allocation factors, regardless of whether they are CP-demand based, or NCP-demand based, can be based on various allocation methods. Many regulatory commissions seek to find reasonable "middle of the road" type allocators to avoid conclusions that may be extreme. FERC has used 12-month average demand figures as allocators unless a demonstrable contrary reason exists.

Shortcomings of Embedded Cost Allocation Studies

The most obvious shortcoming associated with embedded cost studies is the use of estimated demand allocators. At most electric utilities, the majority of the costs are plant-related investments subject to demand allocators. It is implicitly assumed that demand (CP and NCP) is known for each class of service. But few cooperatives know what the individual class demands are because they generally do not measure them. Nor do they support load research efforts to credibly estimate these demands. Instead, they typically rely on research estimates of load that are frequently made by formulas, load factor estimates or other indirect ad hoc methods.

Because of the amount of investment required for electric service, even comparatively small errors in the demand allocators can cause material errors in the allocated costs. Although it is hoped that automatic meter reading (AMR) in the future will alleviate the need to estimate loads, AMR will cause data management issues that may not enhance demand allocators.

Other issues with embedded cost studies include, but are not limited to, the issue of joint (or common) costs. Joint costs occur when the provision of one service is an automatic byproduct of another service. In the electric utility industry, a common example of joint costs involves the relationship between peak distribution and off-peak distribution, where a distribution service is available off-peak hours even though it may be allocated at peak times. Indeed, the inability of embedded cost-of-service studies to deterministically allocate time-differentiated costs is an issue.

Another issue with embedded cost studies may be more of a budget issue than a cost-of-service issue. There frequently is a need to look forward with a future test year. As a result of the detail associated with most cost-of-service models, the level of detail in future test years may not support the models. Although this issue can be resolved, it frequently is not.

When To Complete a Cost-of-Service Study

A common question is how often should a cooperative complete a cost-of-service study? Obviously, if the cooperative is regulated by its state service commission, then the answer may be set by the commission's rules. For cooperatives that are not rate regulated, a study might only be needed every five to 10 years if there has not been a significant change in the operations of the cooperative. Examples of events that would be considered significant include:

- the gain (or loss) of a large load,
- unusually high growth rates,
- extensive storm damage or
- a change in the structure (not just the amounts) of the wholesale rate design.

An increase in the wholesale cost of power generally does not require a cost-of-service study since the cost driver (the increase in purchased power expense) is known, and a direct adjustment to the retail energy and demand charges would be appropriate. Distribution cooperatives and G&T systems also should embrace monthly pass-through riders such as a fuel-cost adjustment rider or a purchase-cost adjustment rider. Pass-through riders permit longer-lived rate structures.

Another instance where a cost-of-service study would not be beneficial is where the cooperative already knows what it wants to do (e.g., the same percentage increase applied to all rate classes). A cooperative is frequently better off accepting its own reasoning than attempting to force a cost model to provide a specific, predetermined response.

Cost of service is a powerful tool in designing retail rates. But it is not always necessary to prepare a cost-of-service study every time a cooperative revises its retail rates. A significant investment in time and effort is necessary in order to collect and develop the information required to complete a cost-of-service study. Therefore, management should evaluate its ultimate intentions and then decide whether a cost-of-service study would be beneficial to its needs.

Glossary

Coincident Peak Demand: A customer or class demand that occurs simultaneously with the peak system demand.

Cost-of-Service Rates: End-use charges that reflect the allocations of the cost-of-service study.

Cost-of-Service Study: An analysis that identifies what it costs the utility to serve its various classes of customers. The cost-of-service study produces cost-of-service rates.

Embedded Cost: The historical booked cost of plant in service and expenses.

Federal Energy Regulatory Commission: An independent agency within the U.S. Department of Energy having jurisdiction over interstate transmission of electricity, natural gas and oil. FERC also regulates wholesale electric rates, natural gas projects and hydroelectric projects.

Marginal Cost: The change in total costs associated with a unit change in the quantity supplied.

Marginal Cost Pricing: The setting of prices at the cost of producing the next unit of output.

National Association of Regulatory Utility Commissioners: A nationwide association representing the state-level public service commissioners who regulate intrastate electricity, natural gas, transportation, telecommunications and water utilities.

Non-Coincident Peak Demand: For a specific distribution cooperative, the highest demand over any given time frame without regard to any other system's demand.

Primary Lines: The lines that typically run from substations to transformers located closer to the loads, where the power is stepped down to be transported over secondary lines.

Revenue Requirement: The overall revenue required to meet the operating expenses and return requirements of a utility.

Secondary Lines: The lines on the outgoing side of the transformer that carry the stepped-down power.

Undue Rate Discrimination: Rate discrimination results when a utility provides service at rates that are not equal to the cost of providing service. Undue discrimination is when the rates cannot be justified.

Additional Resources

Chernick, Paul. (1993). *From Here to Efficiency: Securing Demand-Management Resources, Vol. 5.* Pennsylvania Energy Office.

National Association of Regulatory Utility Commissioners. (January 1992). *Electric Utility Cost Allocation Manual.*

Phillips, Jr., Charles F. (1993). *The Regulation of Public Utilities*, Public Utilities Reports.

Setting Rates Series Is Available Online

The first five parts of this series, "Setting Rates: Best Practices for Electric Cooperatives," are available online through CFC's Extranet and through cooperative.com.

CFC Extranet users should go to CFC's home page, www.nrucfc.coop, and log into the Extranet. From the Extranet, select Tools & Information and then CFC Library. The series is also posted on cooperative.com. Go to: www.cooperative.com/services/retailrates.htm.