The Ratemaking Process

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In order to continue to operate, a utility must have an opportunity to recover its prudently-incurred costs. The ratemaking process determines the utility's allowed revenues and how those revenues are collected. There are three key steps to the ratemaking process:

1. **Determine the revenue requirement.** The total revenue that a utility is authorized to collect through its rates is called the total revenue requirement, or the total cost of service. The utility's revenue requirement is typically determined based on the costs incurred during a test year – a 12-month period that is expected to be representative of costs going forward.
2. **Allocate the revenue requirement among customer classes.** Once the revenue requirement has been determined, a cost-of-service study is performed to determine how to allocate the revenue requirement among the various customer classes according to the relative cost of serving each customer class. (Without a revenue requirement, the cost of service study will only provide the relative proportion of costs that should be borne by each class.) The cost to serve a customer class is determined based on key factors such as the number of customers, class peak demand, and annual energy consumption.
3. **Design rates to recover costs.** After the cost of service study is performed, rates are designed to collect the utility's allowed revenues. The cost of service study provides a benchmark for rate design, but is not the only factor that should be considered when designing rates. Other factors such as simplicity, continuity, efficiency, and equity are important considerations.

Cost of Service Studies

Embedded versus Marginal Cost of Service Studies

There are two types of cost of service studies: (1) embedded cost of service studies, and (2) marginal cost of service studies. Some jurisdictions use both, while others only rely on one type. Embedded cost of service studies are more common than marginal cost of service studies. The primary difference between embedded and marginal cost of service studies is the reliance on historical versus incremental costs to determine allocations among customer classes and inform rate design. Embedded studies focus on the current accounting costs associated with past investments actually providing service, while marginal cost of service studies reflect the incremental costs of serving additional load or customers, or the cost of building a new optimal system at current costs. The rationale for each is described below.

Embedded Cost of Service Studies

An embedded cost-of-service simply takes the total revenue requirement and allocates it among customer classes. The revenue requirement includes both operating expenses and rate base (or legacy debt service), which are largely historical capital costs (less depreciation).[1] In other words, a large portion of the costs allocated to customers in an embedded cost of service study are past capital investments.[2]

Marginal Cost of Service Studies

A *marginal* cost study differs from an embedded cost study in that it is forward-looking and analyzes how the costs of the electric system would change in order to provide an incremental increase in service. Because marginal costs are current or future costs, planning documents are the primary source of data. Such documents might include production cost model outputs, transmission and distribution power flow models, and fuel forecasts.

A marginal cost study is particularly useful for informing rate design, since according to economic theory, prices should be set equal to marginal cost to provide efficient price signals. As described in the 1992 NARUC Electric Utility Cost Allocation Manual:[3]

> *"The major reason for allocating costs using marginal cost principles is to promote economic efficiency and societal welfare by simulating the pricing structure and resulting resource allocation of a competitive market. Competition drives production and consumption to where customers are willing to pay a price for the last or marginal unit consumed equal to the lowest price producers are willing to accept for their product. This situation occurs where the supply (marginal cost) and demand curves intersect."*

What is the appropriate time period over which to measure marginal costs?

In competitive markets, equilibrium is said to exist where short-run marginal costs (the cost of extracting additional output from less efficient existing capacity) is equal to long-run marginal cost (the cost of output from new efficient capacity). For the purposes of determining electric utility rates, it is appropriate to use long-run marginal costs, in part because electric systems intentionally plan for reserve capacity to assure reliability, and therefore are seldom in equilibrium.[4]

Although basing electricity rates on marginal costs would result in efficient prices, it would not necessarily result in the utility recovering its revenue requirement. Rates need to meet the two goals of: (1) allowing utilities to recover their historical costs (as indicated in embedded cost studies), and (2) providing customers with efficient price signals (as indicated in marginal cost studies).

Multiple revenue reconciliation procedures have been developed to adjust marginal costs so that the revenues recovered through rates will equal the utility's revenue requirement.[5] Some regulators rely on embedded cost studies to allocate costs between classes, and then use marginal cost information to inform rate design elements (such as inclining block rates or time-varying rates) within classes.

Cost Allocation Overview

A cost-of-service study is performed in three steps:

1 **Functionalization:** First costs are separated according to function (generation, transmission, distribution, etc.) The function of a cost generally follows the Uniform System of Accounts (USOA), but sometimes a facility that is treated one way for accounting purposes actually serves other functions, such as a distribution substation with transmission switching equipment. A summary of the various functions and examples of their associated costs is provided in Table 1.

2 **Classification:** Costs are classified as energy-related (which vary by the amount of energy (kWh) a customer consumes), demand-related (which vary according to some measure of demand (kW)), or customer-related (which vary by the number of customers, among other factors).

3 **Allocation:** One or more allocation factors are selected for each functionalized and classified cost component, to distribute costs among rate classes. The allocation factors are chosen on the principle of "cost causation," which attempts to spread costs among classes in proportion to their contribution to the factors that caused costs to be incurred (discussed more in the following section). To properly allocate costs, it is important to know the characteristics of each customer class: the number of customers (and the relative costs of providing them with shared services), the energy consumed, the voltage at which customers take service, and the contribution to the peak demands on the system.

Table 1. Standard Functionalization of Costs

Generation	Transmission	Distribution	Customer	General Plant & Overhead Expenses
Debt service O&M Fuel Some transmission lines and substations needed to integrate generation resources	Substations connecting transmission lines Lines (towers, conductors, etc.) O&M	Substations connecting distribution lines to transmission or to other distribution voltages Lines (conductors, poles, conduit, etc.) Line Transformers O&M	Service drops Meters Meter reading Billing Customer service	Office space Computers and technology Communications equipment Pensions Legal and regulatory

Core resources for cost allocation:

- NARUC, *Electric Utility Cost Allocation Manual* (Washington, DC: National Association of Regulatory Utility Commissioners, 1992), available at http://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD
- Paul Garfield and Wallace Lovejoy, *Public Utility Economics* (Englewood Cliffs, NJ: Prentice-Hall, 1964).

Cost Drivers

It is important to understand what the primary cost drivers are in order to assign costs to customers based on cost causation. The most important question the analyst or regulator must ask is "*Why was this particular cost incurred?*"

Energy

Energy-related costs are driven not only by the quantity of energy consumed (kWh), but when and where that energy is consumed. Energy costs may vary by time of day, and energy consumed at lower voltages on the system has greater losses. Most embedded cost studies do not differentiate by time of day, while most marginal cost studies do.

Demand

There are many different types of demand:

- **System Coincident Peak(s)** – Demand during the peak hour(s) for the system as a whole. System coincident peak demand drives a significant portion of generation and transmission capacity costs.
- **Local Coincident Peak(s)** – Demand during the peak hour(s) for a circuit or substation. The aggregate local peak demand on a particular piece of the distribution system is the principal driver of distribution system capacity costs.
- **Class Non-Coincident Peak (NCP)** – Peak demand(s) for a class of customers. This measure of demand is often used as a proxy for local coincident peak demands on the distribution system.
- **Customer Non-Coincident Peak (NCP)** – Peak demand(s) of individual customers. Customer maximum demand drives costs related to equipment that serves a particular customer, such as a dedicated line transformer or the load-related portion of service drops.

Customers

Some costs may be allocated simply based on the class's share of total customers. However, where the utility supplies different customer classes with different types of meters or services, it may be appropriate to use the weighted number of customers, with weights based on class-average meter costs, billing costs, service line costs, etc. Where manual meter reading is still in place, the distance between customers (and thus the time required to read each meter) affects customer-related costs; where automated meter reading is in place, it may be reasonable to apply the same principle (the costs avoided vary with distance between customers).

Choosing Appropriate Allocation Methods

There are numerous different approaches to classifying and allocating costs in a cost-of-service study, and thus different analysts can reach different results.[6] Further,

Table 2. Traditional and Cost-Causal Approaches to Cost

Cost Category		Traditional Approach	Cost-Causal Approach
Production	Baseload Power Plants and Fixed Purchase Costs	Demand	Mostly Energy, some Demand
	Renewable Generation	Mostly Demand	All or mostly Energy
	Cycling Power Plants	Demand	Energy & Demand
	Peakers	Demand	Demand
	Fuel, Purchased Energy	Energy	Energy
Transmission	Transmission	Demand	Demand & Energy
Distribution	Distribution Substations	Demand	Mostly Demand
	Feeders (poles, wires, etc.)	Demand & Customers	Demand & Energy
	Line transformers	Demand & Customers	Demand & Energy
	Secondary	Demand & Customers	Demand
Customer	Service drops and meters	Customers	Class actual use
	Billing and Collection	Customers	Weighted Customers

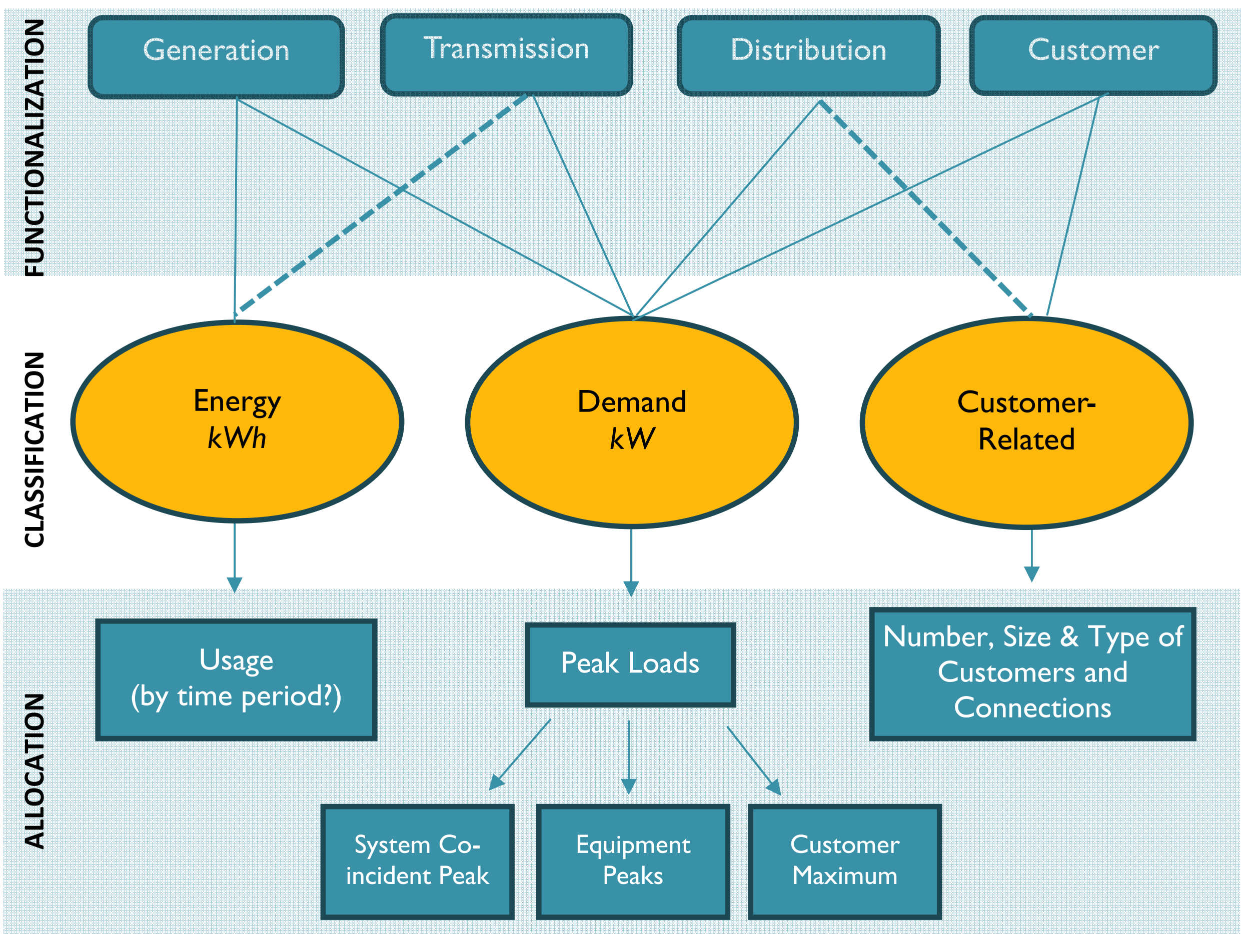
standard classification and allocation methods have changed over time. The table below illustrates two high-level approaches to allocating costs.
Within each approach, there are multiple methodologies. For example, common methods for allocating production plant costs include the following:

- **Peak Demand Methods** (e.g., based on the single system coincident peak (1CP), the 12 monthly system peaks (12CP), or Loss of Load Probability.)
- **Energy Weighting Methods** (e.g., Average and Peak Demand, Equivalent Peaker, Base/Intermediate/Peak)
- **Time Differentiated Methods** (e.g., Production Stacking, Base-Intermediate-Peak, and Probability of Dispatch)

The appropriateness of a method varies based on the individual utility's characteristics. Some jurisdictions consider the results of multiple methodologies in order to determine whether the costs change significantly for a particular class when using a different methodology.

Summary

The graphic below summarizes the embedded cost of service process.



RATE DESIGN FUNDAMENTALS

Guiding Principles

Rates are designed to satisfy numerous objectives, some of which may be in competition with others. In his seminal work, *Principles of Public Utility Rates,* Professor James Bonbright enumerated ten guiding principles for rate design. These principles can be summarized as follows:

1. **Sufficiency:** Rates should be designed to yield revenues sufficient to recover utility costs.
2. **Fairness:** Rates should be designed so that costs are fairly apportioned among different customers, and "undue discrimination" in rate relationships is avoided.
3. **Efficiency:** Rates should provide efficient price signals and discourage wasteful usage.
4. **Customer acceptability:** Rates should be relatively stable, predictable, simple, and easily understandable.

An embedded cost of service study helps to ensure that costs are allocated among customer classes fairly. However, a marginal cost of service study is better suited to the design of efficient rates. This is because the utility's historical investments are sunk costs – they cannot be changed by adjusting electricity consumption going forward. However, future costs can be impacted by customer choices. For example, additional peak demand may cause additional investments in generation, transmission, and distribution capacity. Since these future costs can be avoided, customers should be confronted with prices that reflect these costs when making decisions that affect electricity use. Thus, to promote economic efficiency and societal welfare, electricity rates should be based on future (marginal) costs, as this will send appropriate price signals to inform customer decision-making.

Customer acceptability can be achieved by changing rates gradually, keeping rate designs simple, and by empowering customers to control their electricity bills.

Rate Components

Most electricity customers are charged for electricity using a two-part or three-part tariff, depending on the customer class. Residential customers typically pay a monthly fixed customer charge (e.g., $9 per month) plus an energy charge based on usage (e.g., $0.17 per kilowatt-hour). Commercial and industrial customers frequently pay for electricity based on a three-part tariff consisting of a fixed charge, an energy charge, and a demand charge, because they are large users and have meters capable of measuring demand as well as energy use. The demand charge reflects the maximum amount of power a customer withdraws at any one time, often measured as the maximum one-hour integrated demand (kW) during the billing month.

The customer charge is generally designed to recover the costs to serve a customer that are largely independent of usage, such as metering and billing costs, although some utilities recover a portion of the distribution system costs through customer charges. For customers without demand meters, the energy charge is designed to collect all remaining costs not recovered through the customer charge. For customers with demand charges, utilities typically use those charges to recover a portion of the demand-classified costs, and the remainder through energy charges.

Table 3. Rate Components and Cost Recovery

Rate Component	Costs Typically Recovered through Rate Component
Customer charge *$/customer-month*	Customer-related costs (costs of meters, service drops, meter reading, and billing and collecting)
Energy charge *$/kWh*	Energy-related costs (costs that vary with energy usage). For residential and small commercial customers, the energy charge is also used to collect all costs that are not customer-related.
Demand charge *$/kW*	Demand-related costs (associated with a customer's maximum demand). To accurately reflect capacity cost causation, a large portion of the demand charge would be based on the customer's demand during system coincident peaks or local coincident peaks.

Variations of a Customer Charge

Fixed Customer Charge: A standard fixed customer charge is simple to administer and understand, but reduces customer control over their bills, as the only way to avoid the charge is to stop being a utility customer.

Minimum Bill: Minimum bills are similar to fixed charges, but with one important distinction: minimum bills only apply when a customer's usage is so low that his or her total monthly bill would otherwise be less than this minimum amount. A key advantage to the minimum bill is that it guarantees that the utility will recover a certain amount of revenue from each customer, even if properties are seasonally vacant. One down side is that customers with bills below the minimum have no economic incentive to reduce consumption.

Variations in Energy Charges

Flat Rate: A flat energy rate assesses a uniform rate per kWh for all usage.

Inclining Block Rate: This rate design assesses a higher price per kWh for higher levels of usage, which encourages more efficient energy consumption by pricing incremental usage at levels commensurate with long-run marginal costs.

The simple rate designs above can be measured with simple kilowatt-hour meters. The more complex rate designs that follow require some form of advanced metering.

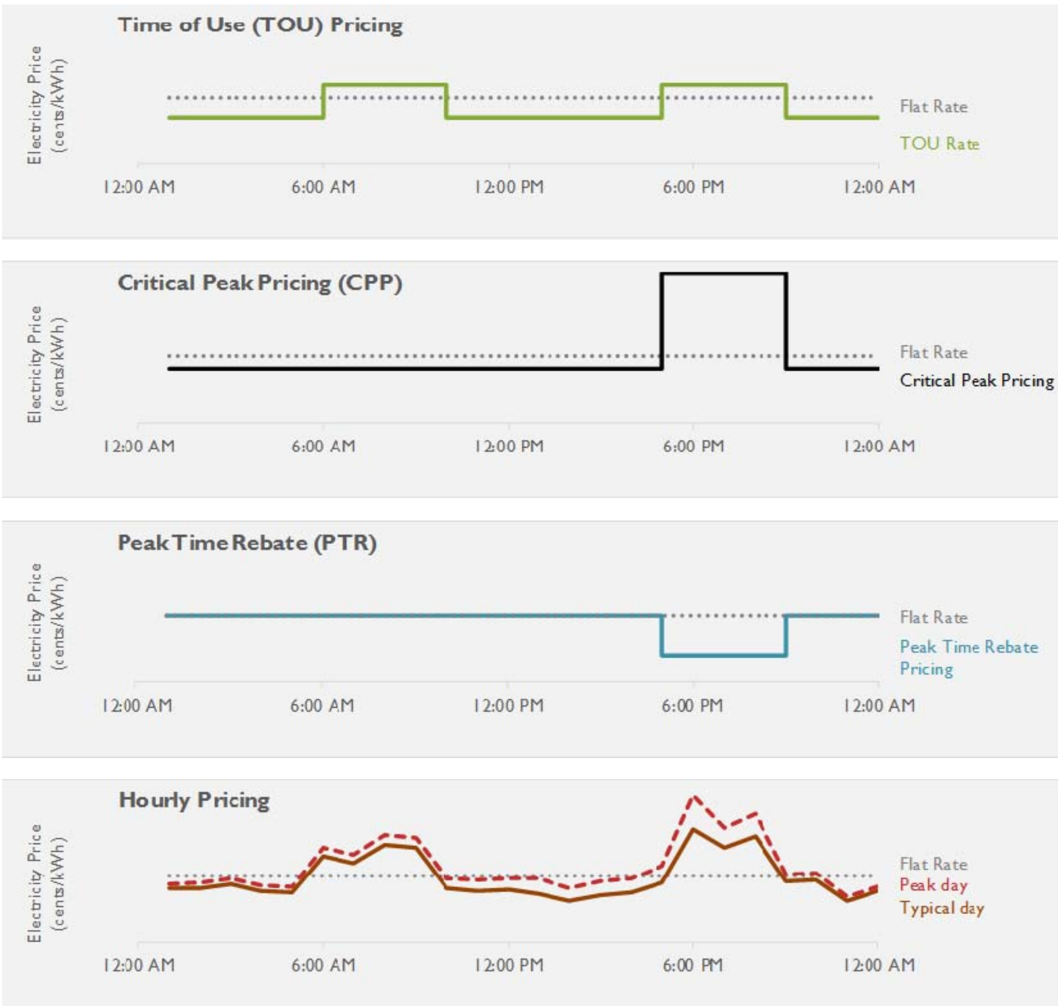
Time-of-Use (TOU) Rate: Under this rate design, electricity prices vary during the day according to a set schedule, which is designed to roughly represent the costs of providing electricity during different hours. A simple TOU rate would have two different prices: one for on-peak periods and another for off-peak periods. This rate design approach can provide customers with a more accurate price signal, which encourages customers to shift their usage from on-peak periods to off-peak periods, thereby reducing system costs.

Critical Peak Pricing (CPP): A critical peak price would assess an extremely high price during only a small number of event hours per year. Customers would be notified the day before an event. For example, a utility may call five critical peak pricing events during the year, each of which lasts for between two and four hours. During the events, electricity is priced at $1.45/kWh. Critical peak pricing can be easily layered on top of a standard TOU rate.

Peak Time Rebates (PTR): A peak-time rebate is the inverse of a CPP rate. Instead of paying a higher price during event hours, a customer is rewarded for reducing his or her demand during those hours. While PTR is very popular with customers, a key challenge with this rate structure is measuring the baseline of what the customer's demand would have been.

Hourly Pricing: Under hourly pricing, electricity rates change hourly based on actual system costs. The manner in which rates change is not pre-set; rather, rates change dynamically in response to system conditions. This form of rate design is generally too complex for most residential customers.

The figure below illustrates four different types of time-varying rates.



Variations in Demand Charges

Standard Non-Coincident Peak Demand Charge: A demand charge attempts to collect demand-related costs based on a customer's maximum demand each month. However, a customer's individual maximum demand is a poor indicator of that customer's demand during system or local peak hours. This is particularly true at the residential level, where it is common for multiple customers to share a single piece of distribution system equipment, such as a transformer. Further, demand is difficult for residential and small commercial customers to understand, monitor, and control.

Time-Limited (or Coincident Peak) Demand Charge: A time-limited demand charge applies only during certain hours of the day. For example, if peak demand for a utility typically occurs between the hours of 4 pm and 8 pm, a demand charge might be designed to only be effective during these hours. While this charge captures more than the actual single peak hour, it is a closer approximation of a customer's demand during the peak hour (which is what drives peaking capacity costs).

Core resources for rate design:

- James Bonbright, *Principles of Public Utility Rates* (New York: Columbia University Press, 1961), available at http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.
- Paul Garfield and Wallace Lovejoy, *Public Utility Economics* (Englewood Cliffs, NJ: Prentice-Hall, 1964).
- Jim Lazar, "Use Great Caution in Design of Residential Demand Charges," Natural Gas & Electricity, February 2016, available at www.raponline.org/document/download/id/7844/
- Paul Chernick et al., "Charge Without a Cause? Assessing Electric Utility Demand Charges on Small Consumers," August 2016, https://electricitypolicy.com/images/2016/August/10Aug2016/Chernick/Chernick2016Aug10final.pdf.
- Melissa Whited, Tim Woolf, and Joseph Daniel, "Caught in a Fix: The Problem with Fixed Charges for Electricity" (Synapse Energy Economics, prepared for Consumers Union, February 9, 2016), http://www.synapse-energy.com/sites/default/files/Caught-in-a-Fix.pdf.
- Jim Lazar and Wilson Gonzalez, "Smart Rate Design for a Smart Future" (Regulatory Assistance Project, July 2015), http://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

Endnotes

[1] The revenue requirement is based on accounting costs as contained in the utility's and balance sheets, property records, operating expenses, plant investment data.

[2] More specifically, it is the undepreciated balance associated with the original cost of utility plant.

[3] NARUC 1992, Page 147

[4] *See, for example,* James Bonbright, Principles of Public Utility Rates (New York: Columbia University Press, 1961). P. 336: "I conclude this chapter with the opinion, which would probably represent the majority position among economists, that, as setting a general basis of minimum public utility rates and of rate relationships, the more significant marginal or incremental costs are those of a relatively long-run variety – of a variety which treats even capital costs or "capacity costs" as variable costs.

[5] For more information, see NARUC (1992) *Electric Utility Cost Allocation Manual*, Chapter 11.

[6] Commonly used cost-of-service study methods are described in the *Electric Utility Cost Allocation Manual*, published by the National Association of Regulatory Utility Commissioners.

About Synapse

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