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RAP®

Electric Cost Allocation for a New Era

A Manual

By Jim Lazar, Paul Chernick and William Marcus

Edited by Mark LeBel

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Regulatory Assistance Project (RAP)®
50 State Street, Suite 3
Montpelier, VT 05602
USA

Telephone: 802-223-8199
Email: info@raponline.org
raponline.org
linkedin.com/company/the-regulatory-assistance-project
twitter.com/regassistproj

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About the Authors

Jim Lazar, senior advisor with the Regulatory Assistance Project, is an economist who studied economics and energy at Western Washington University and the University of Washington. He has maintained a consulting practice in utility regulation and pricing and has made more than 100 appearances as an expert witness in rate proceedings in many different jurisdictions. His first utility rate proceeding was in 1974. As a RAP senior advisor, he has advised utility regulators across the United States and in Europe, India, Asia, Africa and South America. He is a former member of the U.S. Department of Energy Electricity Advisory Committee. Mr. Lazar has published more than 20 reference handbooks and topical papers on utility regulation and planning.

Paul Chernick, president of Resource Insight Inc., studied technology and policy at the Massachusetts Institute of Technology. He has advised clients on a wide range of issues, including restructuring policy; estimation of stranded costs; market price forecasts; market valuation of generation resources and divestiture of generation assets; planning and rate-making for central supply, energy efficiency, renewable and distributed resources, and least-cost compliance with environmental regulations; cost allocation and rate design; transmission and distribution planning; and valuation of environmental externalities. Mr. Chernick has testified in more than 300 regulatory and judicial proceedings. He began his career in 1977 with the Massachusetts attorney general's office.

William Marcus, principal of MCPM Economics — a successor company to JBS Energy Inc., where he worked for 32 years — studied economics at Harvard University and the University of Toronto. He began his energy career with the California Energy Commission in 1978. Mr. Marcus has more than 40 years of experience analyzing utility resource plans, costs and rates. He has prepared cost and rate studies for numerous clients and has testified as an expert witness in more than 40 jurisdictions.

Taken together, the three authors have more than 120 years of experience in cost allocation and rate design issues. They have been qualified and testified as expert witnesses before 43 state utility regulatory agencies, eight Canadian provinces and many other local, state and federal regulatory bodies.

About the Editor

Mark LeBel, associate at the Regulatory Assistance Project, has more than a decade of experience working on the overlapping economics and law of energy and environmental policy in the United States. As a member of RAP's U.S. team, he focuses on rate design and regulatory reform, including compensation for distributed energy resources, the evolution of the electricity system and beneficial electrification.

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Introduction and Overview

The purpose of this manual is to provide a comprehensive reference on electric utility **cost allocation** for a wide range of practitioners, including utilities, intervenors, utility regulators and other policymakers. Cost allocation is one of the major steps in the traditional regulatory process for setting utility rates. In this step, the regulators are primarily determining how to equitably divide a set amount of costs, typically referred to as the **revenue requirement**, among several broadly defined classes of ratepayers. The predominant impact of different cost allocation techniques is which group of customers pays for which costs. In many cases, this is the share of costs paid by residential customers, commercial customers and industrial customers.

> Charting a new path on cost allocation is an important part of creating the fair, efficient and clean electric system of the future.

In addition, the data and analytical methods used to inform cost allocation are often relevant to the final step of the traditional regulatory process, known as **rate design**. In this final step, the types of charges for each class of ratepayers are determined — which can include a per-month charge; charges per **kilowatt-hour** (kWh), which can vary by season and time of day; and different charges based on measurements of **kilowatt** (kW) **demand** — as well as the price for each type of charge. As a result, cost allocation decisions and analytical techniques can have additional efficiency implications.

Cost allocation has been addressed in several important books and manuals on utility regulation over the past 60 years, but much has changed since the last comprehensive publication on the topic — the 1992 *Electric Utility Cost Allocation Manual* from the **National Association of Regulatory Utility Commissioners** (NARUC). Although these works and historic best practices are foundational, the legacy methods of cost allocation from the 20th century are no more suited to the new realities of the 21st century than the engineering of internal combustion engines is to the design of new electric motors. New electric vehicles (EVs) may look similar on the outside, but the design under the hood is completely different. This handbook both describes the current best practices that have been developed over the past several decades and points toward needed innovations. The authors of this manual believe strongly that charting a new path forward on cost allocation is an important part of creating the fair, efficient and clean electric system of the future.

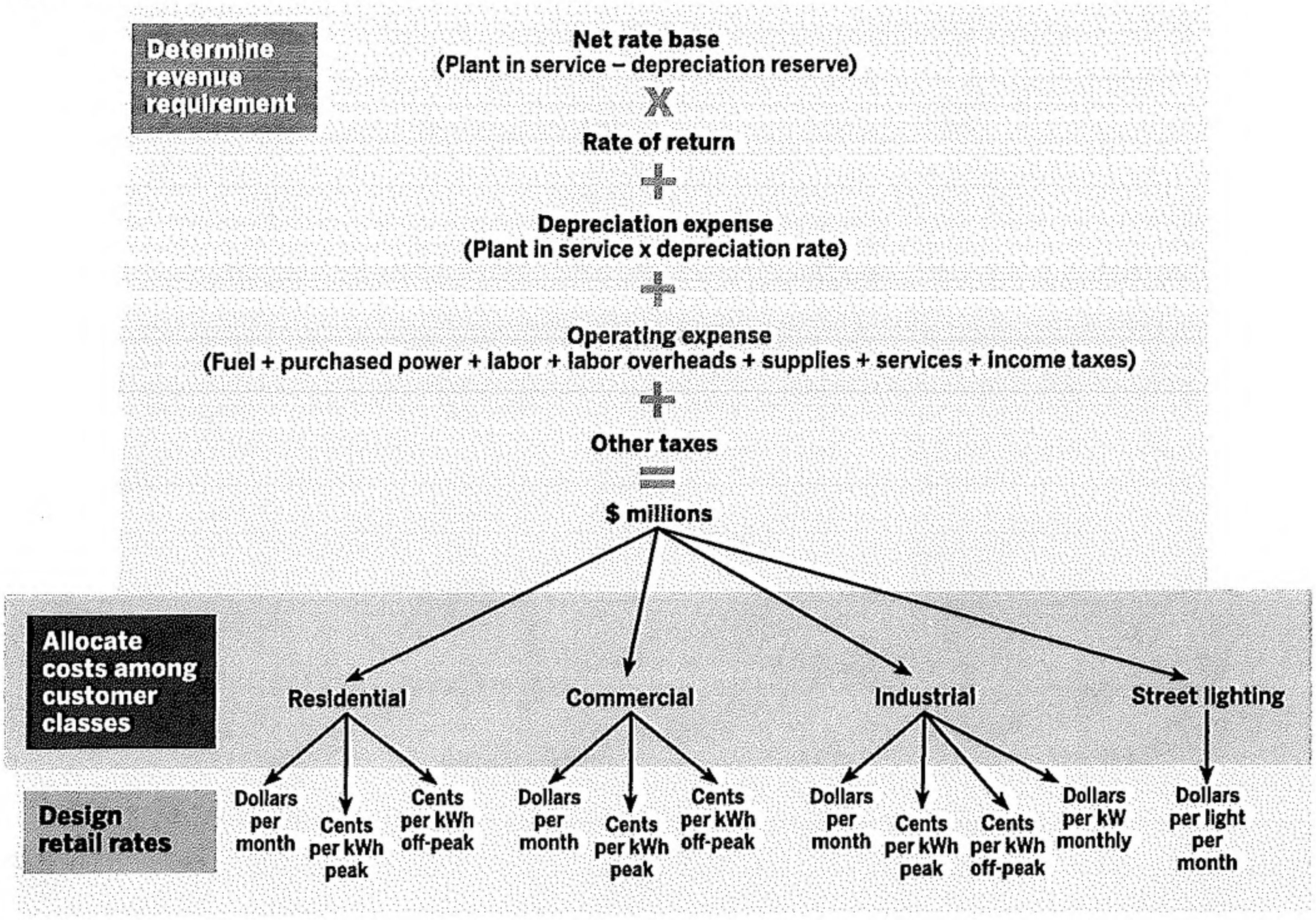
Scope and Context of This Manual

This manual focuses on cost allocation practices for electric utilities in the United States and their implications. Our goal is to serve as both a practical and theoretical guide to the analytical techniques involved in the equitable distribution of electricity costs. This includes background on regulatory processes, purposes of regulation, the development of the electricity system in the United States, current best practices for cost allocation and the direction that cost allocation processes should move. Most of the elements of this manual will be applicable elsewhere in the Americas, as well as in Europe, Asia and other regions.

The rate-making process for **investor-owned utilities** (IOUs) has three steps: (1) determining the annual revenue requirement, (2) allocating the costs of the revenue requirement among the defined rate classes and (3) designing the rates each customer ultimately will pay. Figure 1 on the next page presents a highly simplified version of these steps.

In the cost allocation step, there are two major quantitative frameworks used around the United States: **embedded cost of service studies** and **marginal cost of service studies**. Embedded cost studies typically are based on a single year-long period, using the embedded cost revenue requirement and customer usage patterns in that year to divide up costs.

Figure 1. Simplified rate-making process



Marginal cost of service studies, in contrast, look at how costs are changing over time in response to changes in customer usage.

Regardless of which framework will be used, an enormous amount of data is typically collected first, starting with the costs that make up the revenue requirement, **energy** usage by **customer class** and measurements of demand at various times and often extending to data on **generation** patterns. Furthermore, when the quantitative **cost of service study** is completed, regulators typically don't take the results as the final word, often making adjustments for a wide range of policy considerations after the fact.

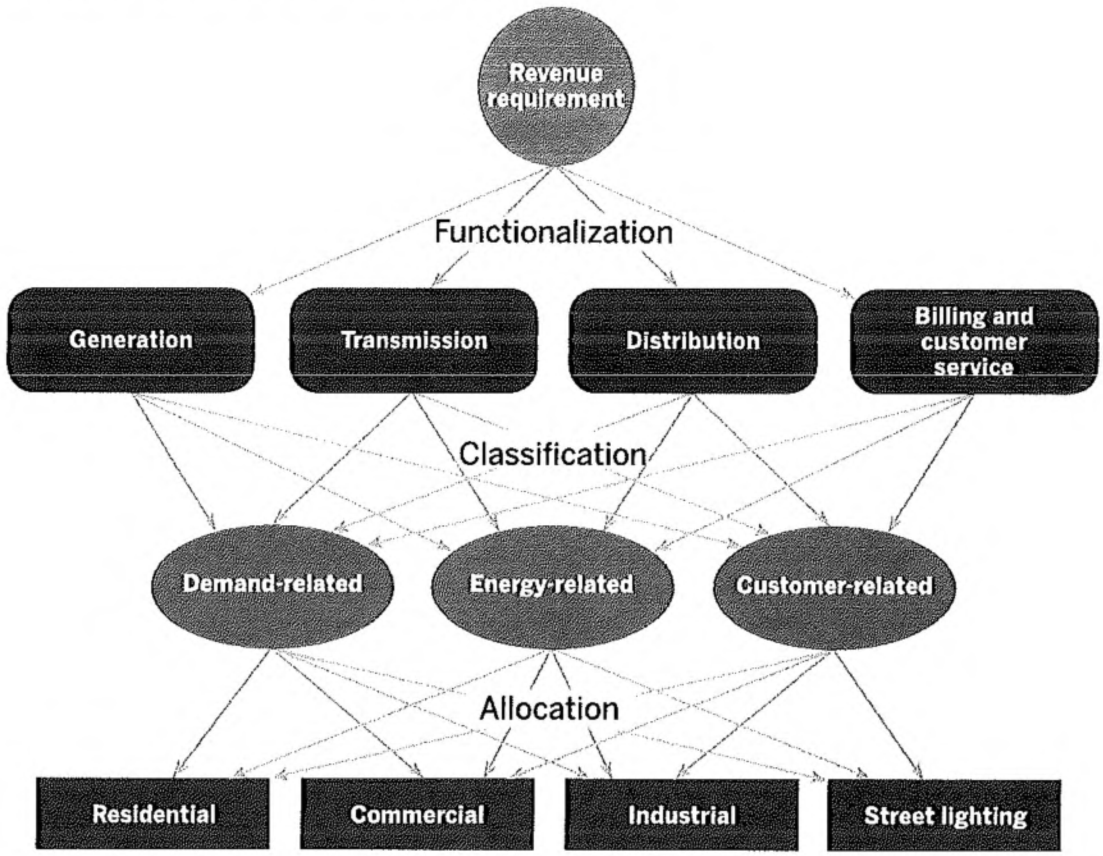
Traditionally, the analysis for an embedded cost of service study is itself divided into three parts: **functionalization, classification** and **allocation**. Figure 2 on the next page shows the traditional flowchart for this process.

The analysis for a marginal cost of service study starts with a similar functionalization step, but that is followed by estimation of marginal unit costs for each element of the system, calculation of a **marginal cost revenue requirement** (MCRR) for each class as well as for the system as a whole, and then **reconciliation** with the annual embedded cost revenue requirement.

This cost allocation manual is intended to build upon previous works on the topic and to illuminate several areas where the authors of this manual disagree with the approaches of the previous publications. Important works include:

- *Principles of Public Utility Rates* by James C. Bonbright (first edition, 1961; second edition, 1988).
- *Public Utility Economics* by Paul J. Garfield and Wallace F. Lovejoy (1964).

Figure 2. Traditional embedded cost of service study flowchart



- *The Economics of Regulation: Principles and Institutions* by Alfred E. Kahn (first edition Volume 1, 1970, and Volume 2, 1971; second edition, 1988).
- *The Regulation of Public Utilities* by Charles F. Phillips (1984).
- The 1992 NARUC *Electric Utility Cost Allocation Manual.*

Of course, cost allocation has been touched upon in other works, including RAP's publication *Electricity Regulation in the United States: A Guide* by Jim Lazar (second edition, 2016). However, since the 1990s, there has been neither a comprehensive treatment of cost allocation nor one that addresses the emerging issues of the 21st century. This manual incorporates the elements of these previous works that remain relevant, while adding new cost centers, new operating regimes and new technologies that today's cost analysts must address.

Continuing Evolution of the Electric System

Since the establishment of electric utility regulation in the United States in the early 20th century, the electric system has undergone periods of great change every several decades. Initial provision of electricity service in densely populated areas was followed by widespread rural electrification in the 1930s and 1940s. In the 1950s and 1960s, **vertically integrated utilities**, owning generation, **transmission** and **distribution** simultaneously, were the overwhelmingly dominant form of electricity service across the entire country.

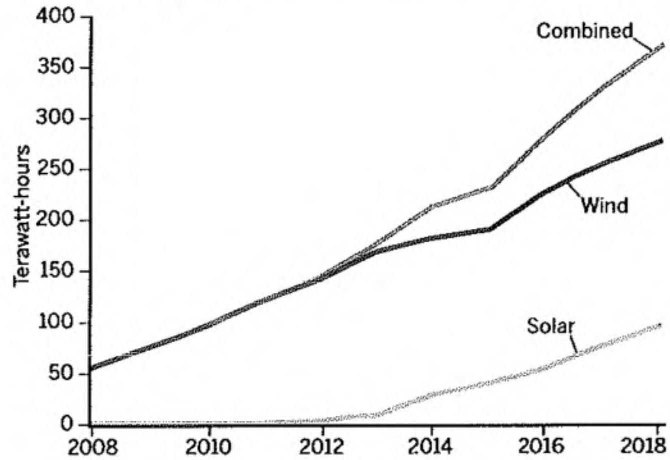
However, the oil crisis in the 1970s sparked a chain reaction in the electric industry. That included a new focus by utilities on **baseload generation** plants, typically using coal or nuclear power. At the same time, the federal government began to open up competition in the electric system with the passage of the **Public Utilities Regulatory Policy Act** (PURPA) of 1978. PURPA dictated that each state utility commission consider a series of standards to reform rate-making practices, including **cost of service**.[1] Nearly every state adopted the recommendation that rates should be based on the cost of service, but neither PURPA nor state regulators were clear about what that should mean. This has led to a fertile legal and policy discussion about the cost of service, how to calculate it and how to use it. PURPA also required that utilities pay for power from **independent power producers** on set terms.

In the 1970s and early 1980s, major increases in oil prices, the completion of expensive capital investments in coal and nuclear generation facilities and general inflation all led to significantly higher electricity prices across the board. These higher prices, in combination with PURPA's requirement for set compensation to independent power producers, led to demands by major consumers to become wholesale purchasers of electricity. This in turn led to the Energy Policy Act of 1992, which enabled the broader restructuring of the electric industry in much of the country around the turn of the 20th century.

The key texts and most of the analytical principles currently used for cost allocation were developed between the 1960s and early 1990s. Since that time, the electric system in the United States has been undergoing another period of dramatic change. That includes a wide range of interrelated advancements in technology, policy and economics:

- Major advances in data collection and analytical capabilities.
- Restructuring of the industry in many parts of the country, including new wholesale electricity markets, new retail markets and new market participants.
- New consumer interests and technologies that can be deployed **behind the meter**, including clean **distributed generation, energy efficiency, demand response**, storage and other energy management technologies.
- Dramatic shifts in the relative cost of technologies and fuels, including massive declines in the price of **variable renewable resources** like wind and solar and sharp declines in the cost of energy storage technologies.
- The potential for beneficial electrification of end uses that currently run directly on fossil fuels — for example, electric vehicles in place of vehicles with internal combustion engines.

Figure 3. Increase in US wind and solar generation from 2008 to 2018



Data source: U.S. Energy Information Administration. (2019, February). *Electric Power Monthly*. Table 1.1.A. Retrieved from https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_1_01_a

Many, if not all, of these changes have quantifiable elements that can and should be incorporated directly into the regulatory process, including cost allocation. The increased development of renewable energy and the proliferation of more sophisticated meters provide two examples.

Figure 3 illustrates the dramatic increase in wind and solar generation in the United States in the last decade, based on data from the U.S. Energy Information Administration.

Traditional cost allocation techniques classify all utility costs as **energy-related, demand-related** or **customer-related**. These categories were always simplifications, but they must be reevaluated given new developments. Some legacy cost allocation methods would have treated wind and solar generation entirely as a demand-related cost simply because they are capital investments without any variable **fuel costs**. However, wind and solar generation does not necessarily provide firm **capacity** at peak times as envisioned by the legacy frameworks, and it displaces the need for fuel supply, so it doesn't fit as a demand-related cost.

1 The PURPA rate-making standards are set forth in 16 U.S.C. § 2621. Congress in 2005 adopted a specific requirement that cost of service studies take time of usage into account; this is set forth in 16 U.S.C. § 2625.

Table 1. Types of meters and percentage of customers with each in 2017

	Residential	Commercial	Industrial
Advanced metering infrastructure	52.2%	50.0%	44.5%
Automated meter reading	29.5%	26.5%	28.0%
Older systems	18.3%	23.5%	27.5%

Data source: U.S. Energy Information Administration. *Annual Electric Power Industry Report, Form EIA-861: 2017* [Data file]. Retrieved from https://www.eia.gov/electricity/data/eia861/

In addition, many utilities now collect much more granular data than was possible in the past, due to the widespread installation of **advanced metering infrastructure** (AMI) in many parts of the country and other advancements in the monitoring of the electric system. As a result, utility analysts often have access to historical hourly usage data for the entire utility system, each distribution **circuit**, each customer class and, increasingly, each customer. Some **automated meter reading** (AMR) systems also allow the collection of hourly data, typically read once per billing cycle. Table 1 shows the recent distribution of meter types across the country, based on data from the U.S. Energy Information Administration. Improved data collection allows for a wide range of new cost allocation techniques.

In addition, meters have been primarily treated as a customer-related cost in older methods because their main purpose was customer billing. However, advanced meters serve a broader range of functions, including demand management, which in turn provides system capacity benefits, and **line loss** reduction, which provides a system energy benefit. This means the benefits of these meters flow beyond individual customers, and logically so should responsibility for the costs.

These are just two examples of how recent technological advances affect appropriate cost allocation. In subsequent chapters, this manual will address each major cost area for electric utilities, the changes that have occurred in how costs are incurred and how assets are used, and the best methods for cost allocation.

Principles and Best Practices

There is general agreement that the overarching goal of cost allocation is equitable division of costs among customers. Unfortunately, that is where the agreement ends and the arguments begin. Two primary conceptual principles help guide the way to the right answers:

1. Cost causation: Why were the costs incurred?
2. Costs follow benefits: Who benefits?

In some cases these two frameworks point to the same answer, but in other cases they conflict. The authors of this manual believe that "costs follow benefits" is usually, but not always, the superior principle. Other helpful questions can be asked to illuminate the details of particularly difficult questions, such as:

- If certain resources were not available, which services would not be provided, and what different resources would be needed to provide those services at least cost?
- If we did not serve this need in this way, how would costs change?

In the end, cost allocation may be more of an art than a science, since fairness and equity are often in the eye of the beholder. In most situations, cost allocation is a zero-sum process where lower costs for any one group of customers lead to higher costs for another group. However, the techniques used in cost allocation have been designed to mediate these disputes between competing sets of interests. Similarly, the data and analysis produced for the cost allocation process can also provide meaningful information to assist in rate design, such as the seasons and hours when costs are highest and lowest, categorized by system component as well as by customer class.

In that spirit, we would like to highlight the following current best practices discussed at more length in the later chapters of this manual. To begin, there are best practices that apply to both embedded and marginal cost of service studies:

- Treat as customer-related only those costs that actually vary with the number of customers, generally known as the **basic customer method**.
- Apportion all shared generation, transmission and distribution assets and the associated operating expenses

on measures of usage, both energy- and demand-based.

- Ensure broad sharing of overhead investments and **administrative and general (A&G) costs**, based on usage metrics.
- Eliminate any distinction between **"fixed" costs** and "variable" costs, as capital investments (including new technology and data acquisition) are increasingly substitutes for fuel and other short-run variable operating costs.
- Where future costs are expected to vary significantly from current costs, make the cost trajectory an important consideration in the apportionment of costs.

Second, there are current best practices specific to embedded cost of service studies:

- Classify and allocate generation capacity costs using a time-differentiated method, such as the **probability-of-dispatch** or **base-intermediate-peak** (BIP) methods, or classify capacity costs between energy and demand using the **equivalent peaker method**.
- Allocate demand-related costs for generation using a broad peak measure, such as the **highest 100 hours** or the **loss-of-energy expectation**.
- Classify and allocate the costs of transmission based on its purpose, with any demand-related costs allocated based on broad peak periods for regional networks and narrower ones for local networks.
- Classify distribution costs using the basic customer method, and divide the vast majority of costs between demand-related and energy-related using an energy-weighted method, such as the **average-and-peak method** that many natural gas utilities use.
- Allocate demand-related distribution costs using appropriately broad peak measures that capture the hours with high usage for the relevant system elements while appropriately accounting for **diversity** in customer usage.
- Ensure that customer connection and service costs appropriately reflect differences between customer classes by using either specific cost studies for each element or a weighted customer approach.
- Functionalize and classify AMI and billing systems according to their multiple benefits across different elements and aspects of the electric system.

Lastly, there are current best practices for marginal cost of service studies:

- Use **long-run marginal costs** for generation that reflect lower greenhouse gas emissions than the present system, and recognize the costs of emissions that do occur as **marginal costs** during those periods.
- Analyze whether demand response, storage or market capacity purchases are cheaper than a traditional peaking **combustion turbine** as the foundation of marginal generation capacity cost.
- Use an expansive definition of marginal costs for transmission and distribution, including automation, controls and other investments in avoiding capacity or increasing reliability, and consider including replacement costs over the relevant timeframe.
- Recognize marginal line losses in each period.
- Functionalize marginal costs in **revenue reconciliation**; use the **equal percentage of marginal cost** technique by function, not in total.

Path Forward and Need for Reform

Our power system is changing, and cost allocation methods must also change to reflect what we are experiencing. Key changes in the power system that have consequences for how we allocate costs include:

- Renewable resources are replacing fossil generation, substituting invested capital in place of variable fuel costs.
- **Peaking resources** are increasingly located near **load** centers, eliminating the need for transmission line investment to meet **peak demand**. Long transmission lines are often needed to bring baseload coal and nuclear resources, and to bring wind and other renewable resources, even if they may have limited peaking value relative to their total value to the power system.
- Storage is a new form of peaking resource — one that can be located almost anywhere and has low variable costs. Storage can help avoid generation, transmission and distribution **capacity-related costs**. The total costs of storage need to be assigned to the proper time period for equitable treatment of customer classes.

- Consumer-sited resources, including solar and storage, are becoming essential components of the modern **grid**. The **distribution system** may also begin to serve as a gathering system for power flowing from locations of local generation to other parts of the utility service territory, the opposite of the historical top-down electric delivery model.
- **Smart grid** systems make it possible to provide better service at lower cost by including targeted energy efficiency and demand response measures to meet loads at targeted times and places and other measures to take advantage of improved data and operational capabilities.

Unfortunately, older techniques, even those resulting from detailed inquiries by cutting-edge regulators in recent decades, may not be sufficiently sophisticated to incorporate new technologies, more granular data and advancements in analytical capabilities. As a result, innovations are needed in the regulatory process to mirror the changes taking place outside of **public utilities commissions.**

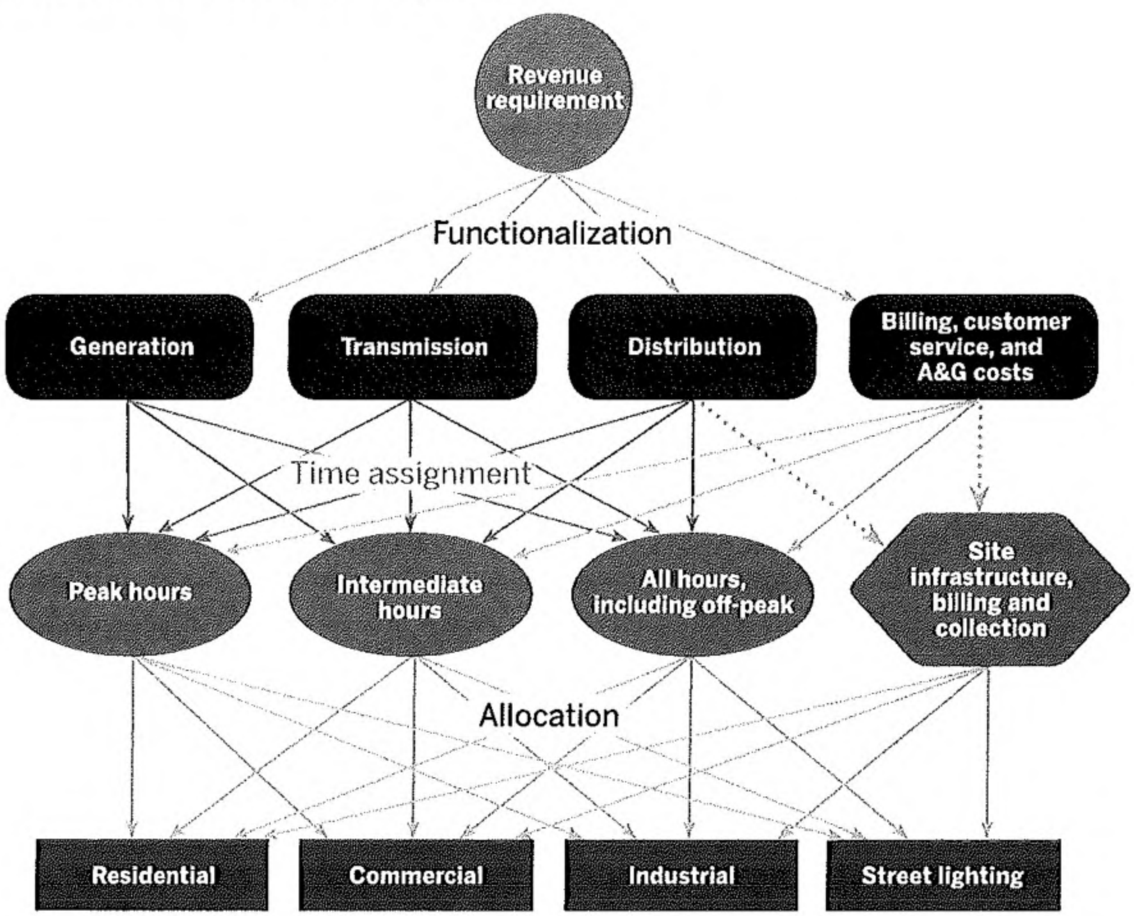
For all cost of service studies, these innovations could include:

- Clear distinction between shared assets and customer-specific assets in the accounting for distribution costs.
- Clearer tracking of distinctions between system costs and overhead investments and expenses at all stages of the rate-making process.
- More accurate definitions of rate classes based on emerging economic and service characteristic distinctions between customers.
- Distinction between loads that can be controlled to draw power primarily at low-cost periods and those that are inflexible.

For embedded cost of service studies, innovative **hourly allocation** techniques could incorporate a number of advances, including:

- Hourly methods for generation: Most generation costs

Figure 4. Modern embedded cost of service study flowchart



should be assigned to the hours in which the relevant facilities are actually used and to all hours across the year, not solely based on measurements in a subset of these hours.

- Hourly methods for transmission: Transmission costs must be examined to determine the purpose and usage patterns, and costs must be assigned to the hours when the transmission services are utilized to serve customer needs.
- All shared distribution costs should be apportioned based on the time periods when customers utilize these facilities. The system is needed to provide service in every hour, and in most cases a significant portion of the distribution system cost should be assigned volumetrically to all hours across the year.
- Billing, customer service and A&G costs that do not vary based on consumption should be functionalized separately.
- **Site infrastructure** to connect customers, billing and collection should be a separate classification category.

Figure 4 shows an example of a modern time-based allocation method in a reformed flowchart.

Innovation in marginal cost of service studies could take the form of more granular hourly marginal cost analysis for the generation, transmission and shared distribution elements of the system. Alternatively, a more conceptual shift to the **total service long-run incremental cost** method developed for the restructuring of the telecommunications industry should be considered. This method estimates the cost of building a new optimally sized system using current technologies and costs. This avoids a number of significant issues with traditional marginal cost of service studies, particularly the problem of significant swings in estimates based on the presence or absence of excess capacity, but it comes with additional data requirements and new uncertainties.

These proposed innovations, regardless of whether they are adopted widely, shed new light into the foundations of cost allocation and may help the reader gain insight into the underlying questions. More generally, we hope that readers find this manual useful as they undertake the complex task of apportioning utility costs among functions, customer classes and types of service and that they join us in finding the best path forward.

Guide to This Manual

After this introduction and summary, this manual is divided into five parts:

- Part I: Chapters 1 through 4 lay out principles of economic regulation of electric utilities, background on the rate-making process, and definitions and descriptions of the electric system in the United States. Readers who are new to rate-making and utility regulation should start here for the basics.[2] Much of this material likely will be familiar to an experienced practitioner but emphasizes key issues relevant to the remainder of the manual.
- Part II: Chapters 5 through 8 cover the important definitions, basic techniques and overarching issues in cost allocation. Some of this material may be familiar to an experienced practitioner but also lays out the issues facing cost allocation.
- Part III: Chapters 9 through 17 delve deeply into the subject of embedded cost of service studies, including discussion of historic techniques, current best practices and key reforms.
- Part IV: Chapters 18 through 26 cover the field of marginal cost of service studies, including historical development, current best practices and key needed reforms.
- Part V: Chapters 27 and 28 cover what happens after the completion of the quantitative studies, including presentation of study results and adjustments, and the relationship between cost allocation and rate design.

The conclusion wraps up with final thoughts.

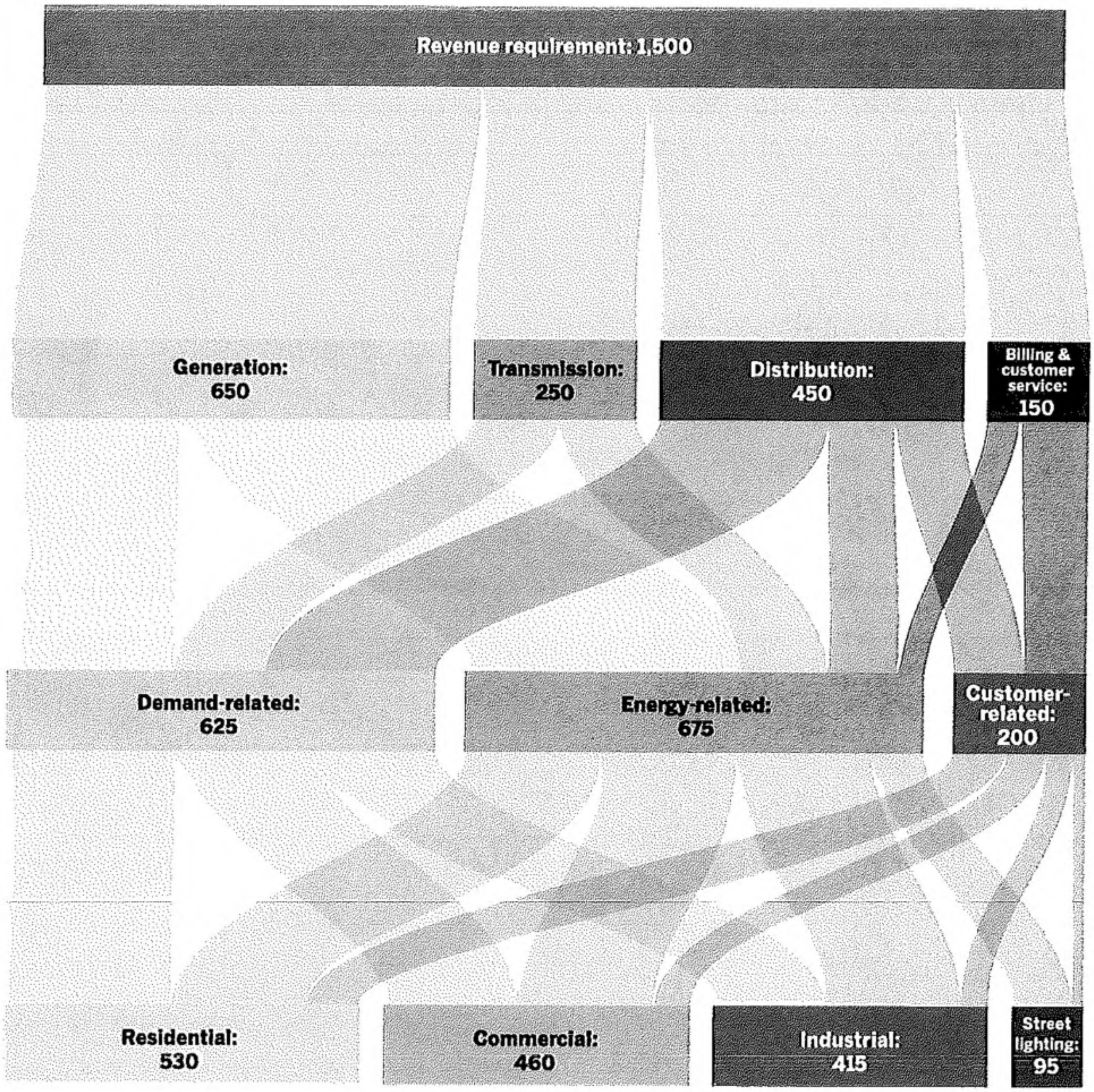
Each part of this manual ends with a list of works cited. Terms defined in the glossary are set off in boldface type where they first appear in the text.

2 For a more detailed handbook on the structure and operation of the industry, see Lazar, J. (2016). *Electricity Regulation in the United States: A Guide* (2nd ed.). Montpelier, VT: Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/

Visual display of cost allocation results

Like much of utility regulation, visual display of information in cost allocation tends to be dry and difficult to understand. Much of the analytical information for cost allocation tends to be displayed in large tables that only experts can interpret. Simple flowcharts, such as Figure 2 on Page 16, are also quite common and convey little substantive information. Nevertheless, it should be possible to convey cost allocation results in a meaningful way that a wider audience can understand. One possibility is to convert the traditional flowcharts into Sankey diagrams, where the width of the flows is proportional to the magnitude of the costs. Figure 5 shows this type of diagram for a traditional embedded cost of service study.

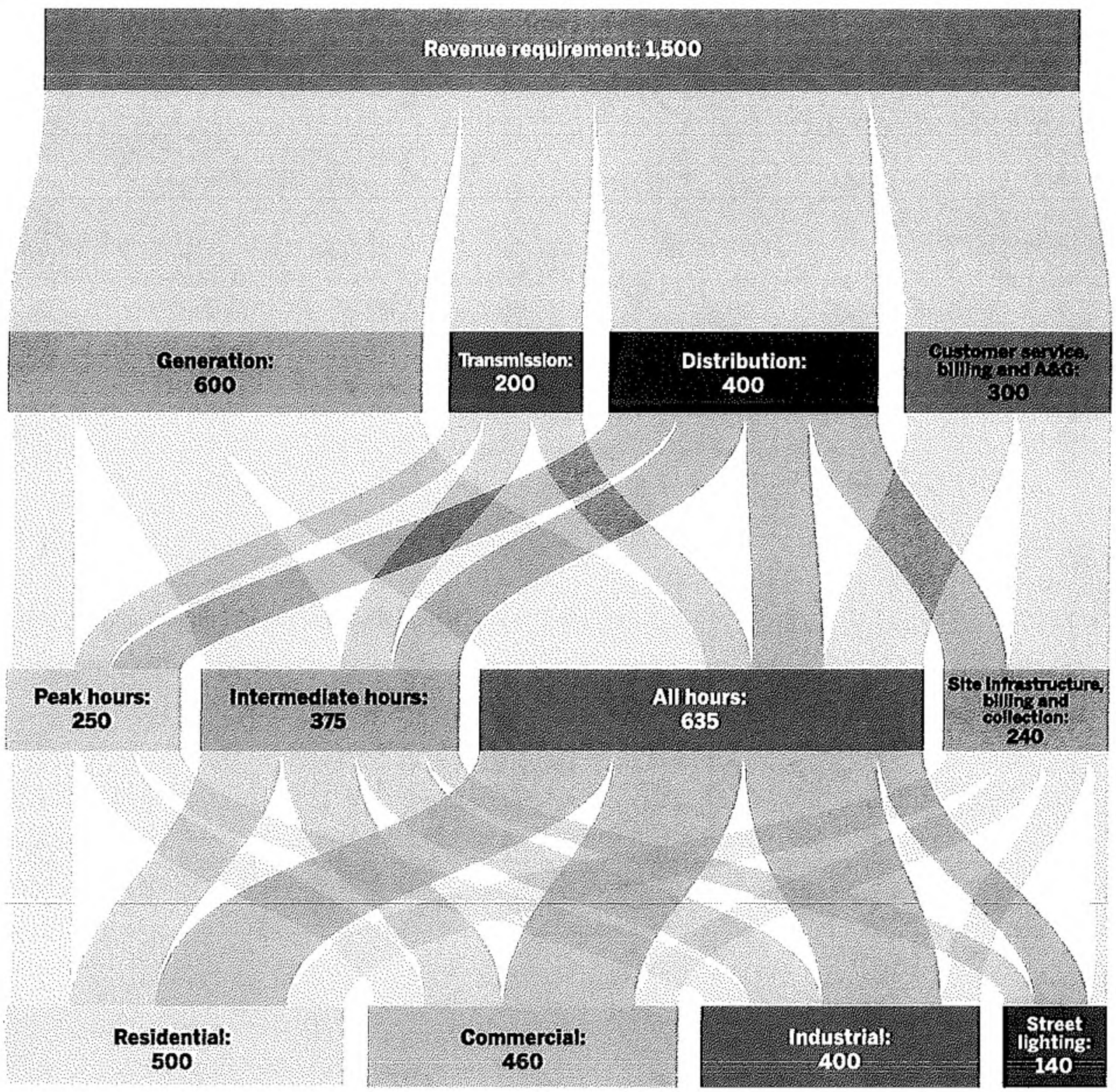
Figure 5. Sankey diagram for traditional embedded cost of service study



A Sankey diagram can display a tremendous amount of information in a way that is reasonably understandable. At the top, it begins with the overall revenue requirement, then splits into three functions. Next, each function splits into the different classifications, which are then allocated by customer class. At each step, the overall costs stay constant, but the relative sizes for each function, classification and customer class are readily apparent. Additionally, the colors in the diagram can be used to indicate additional distinctions. Figure 6 is a Sankey diagram for a more complex reformed embedded cost of service study. Like Figure 5, it shows illustrative results that are feasible with certain allocation techniques. In contrast, the flowcharts in figures 2 and 4 show all the different allocation possibilities with arrows linking different categories.

As the Sankey diagram becomes more complex, it can be less intuitive. Yet it is likely a much more understandable visual representation of the key elements of a cost of service study.

Figure 6. Sankey diagram for modern embedded cost of service study



Part I:

Economic Regulation and the Electric System in the United States

1. Economic Regulation in the U.S.

Economic regulation of privately owned business dates back to the Roman Empire and was a significant feature of government in medieval England, where accommodation prices at inns were regulated because travelers typically had only a single choice when arriving at the end of a day on foot or horseback. In the later medieval period, the English Parliament regulated bakers, brewers, ferrymen, millers, smiths and other artisans and professionals (Phillips, 1984, p. 77). This tradition was brought to the United States in the 19th century, when a series of Supreme Court opinions held that grain elevators, warehouses and canals were monopoly providers of service "affected with a public interest" and that their rates and terms of service could therefore be regulated.[3]

> Property does become clothed with a public interest when used in a manner to make it of public consequence, and affect the community at large. When, therefore, one devotes his property to a use in which the public has an interest, he, in effect, grants to the public an interest in that use, and must submit to be controlled by the public for the common good ...
>
> — U.S. Supreme Court, Munn v. Illinois, 94 U.S. 113, 126 (1877)

1.1 Purposes of Economic Regulation

The primary purpose of economic regulation has always been to prevent the exercise of monopoly power in the pricing of essential public services. Whether applying to a single inn along a stagecoach route or an electric utility serving millions of people, the essence of regulation is to impose on monopolies the pricing discipline that competition imposes on competitive industries and to ensure that consumers pay only a fair, just and reasonable amount for the services they receive and the commodities they consume. Historically, electric utility service is considered a "natural monopoly" where the cost of providing service is minimized by having a single system serving all users. In recent years, competition has been introduced into the power supply function in some areas. The delivery service remains a natural monopoly in all areas, however, and in much of the U.S., power supply is provided at retail by only a single monopoly utility.

Over time, legislative and regulatory bodies have identified subsidiary purposes of regulation, but these all remain subordinate to this primary purpose of preventing the abuse of monopoly power. These subsidiary purposes include:

- Defining and assuring the adequacy of service for customers, including reliability and access to electric service at reasonable prices.
- Setting prices so that the utility has a reasonable opportunity to receive revenue sufficient to cover prudently incurred costs, provide reliable service and allow the utility to access capital.
- Avoiding unnecessary and uneconomic expenditures or protecting customers from the costs of imprudent actions.
- Encouraging or mandating practices deemed important for societal purposes, such as reducing environmental damage and advancing technology.
- Managing intentional shifts in cost responsibility from one customer group to another, such as economic development discounts for industrial customers or assistance for low-income and vulnerable customers.

When monopoly power ceases to be a concern, as when there are many buyers and sellers in a transparent market, the basis for imposing price regulation evaporates. Transportation and telecommunications services used to be regulated in the United States, but as technology changed in a way that

3 Munn v. Illinois, 94 U.S. 113 (1877). The term "affected with a public interest" originated in England around 1670, in two treatises by Sir Matthew Hale, Lord Chief Justice of the King's Bench, De Portibus Maris and De Jure Maris. Munn v. Illinois, at 126-128.

allowed competition, policymakers eliminated the economic regulation, or at least changed the essential features of the regulatory structure. A similar phenomenon has occurred with the introduction of wholesale markets for electricity generation in many parts of the country.

James Bonbright, regarded as the dean of utility rate analysts, set out eight principles that are routinely cited today.

1.2 Basic Features of Economic Regulation

To prevent the exercise of monopoly power, the primary regulatory tool used by governments has been control over the prices the regulated company charges. During the decline of the Roman Empire, emperors issued price edicts for more than 800 articles based on the cost of production (Phillips, 1984, p. 75). Utility regulators today review proposals for rates from utilities and issue orders to determine a just and reasonable rate, typically based on the cost of service. However, price regulation raises the question of the quality and features of the product or service. Inevitably, this means that price regulation must logically extend to other features of the product or service. In the case of electricity, this means utility regulators typically have regulatory authority over the terms of service and often set standards for reliability to ensure a high-quality product for ratepayers.

In the regulation of prices for utility service, the prevailing practice, known as **postage stamp pricing**, is to develop separate sets of prices for a relatively small and easily identifiable number of classes of customers. For electric utilities, one typical class of customers is residential. For a given utility and its service territory, all customers in this class pay the exact same prices. Postage stamp pricing clearly deviates from strict cost-based pricing but addresses a number of regulatory needs. It keeps the process relatively simple by limiting the number of outputs that need to be produced to one set of rates for each broad customer class. Since rates need to be tied to the cost of service, this logically implies that the cost of service must be determined separately for each rate class, which is one of the key outputs of the cost allocation phase of a **rate case**.

Postage stamp pricing also puts an end to one of the unfair pricing strategies monopolies undertake, known as price discrimination. Price discrimination — that is, strategically charging some customers more than others — helps a monopolist maximize profits but also serves as a way for an unregulated monopolist to punish some customers and reward others. Of course, different pricing can be appropriate for customers that incur different costs.

> We are asking much of regulation when we ask that it follow the guide of competition. As Americans, we have set up a system that indicates we have little faith in economic planning by the government. Yet, we are asking our regulators to exercise the judgment of thousands of consumers in the evaluation of our efficiency, service and technical progress so that a fair profit can be determined. Fair regulation is now, and always will be, a difficult process. But it is not impossible.
>
> — Ralph M. Besse, American Bar Association annual meeting, August 25, 1953 (Phillips, 1984, p. 151)

1.3 Important Treatises on Utility Regulation and Cost Allocation

This handbook recognizes the pathbreaking work done by cost and rate analysts in the past. It is important to review these foundational works, recognize the wisdom that is still current and identify how circumstances have changed to where some of their theories, methodologies and recommendations are no longer current with the industry.

James Bonbright is regarded as the dean of utility rate analysts. His book *Principles of Public Utility Rates*, first published in 1961, addresses all of the elements of the regulatory process as it then stood, with detailed attention to cost allocation and rate design. Bonbright set out eight principles that are routinely cited today (1961, p. 291):

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.

2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. ...
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use.

Of these, principles 6 and 7 are the most closely related to cost allocation.

Bonbright's chapters on marginal costs (Chapter 17) and fully distributed costs (Chapter 18) are most relevant to this manual's purpose. His analysis of marginal costs carefully distinguishes between **short-run marginal costs** (in which capital assets are not changeable) and long-run marginal costs (in which all costs are variable) and discusses which are most applicable for both cost allocation and rate design. A second edition of this book, edited by Albert Danielsen and David Kamerschen, was published posthumously in 1988.

Paul Garfield and Wallace Lovejoy published their book *Public Utility Economics* in 1964. This text focuses on the economic structure of the industry and the need to have costs and rates measured in terms that elicit rational response by consumers. This text also provides an excellent set of principles for cost allocation and rate design with respect to the shared capacity elements of costs:[4]

1. All service should bear a portion of capacity costs.
2. Capacity charges attributed to each user should reflect the amount of time used, peak characteristics, interruptible characteristics and diversity.
3. Customers with continuous demand should get a bigger share of capacity costs than those with intermittent demand, because the intermittent demand customers have diversity and can share capacity.
4. No class gets a free ride. Every class, including fully **interruptible customers**, must contribute something to the overall system costs in addition to the variable costs directly attributable to its usage.

Alfred Kahn first published *The Economics of Regulation* in two volumes in 1970 and 1971, and a second edition was issued in 1988. Kahn raised the innovative notion of using marginal costs, rather than **embedded costs**, as a foundation of rate-making generally and cost allocation and rate design more specifically. Some states use this approach today. Kahn also served as a regulator, as the chair of both the New York Public Service Commission and the federal Civil Aeronautics Board, which oversaw the deregulation of airlines.

Charles Phillips published *The Regulation of Public Utilities* in 1984, and subsequent editions were released in 1988 and 1993. Phillips wrote in the post-PURPA era, at a time when utility construction of major baseload generating units was winding down. He addressed the desirability of recognizing the difference between baseload and peaking investments as well as the evolution of these cost differentiations into **time-varying rates**. Up to that time, few attempts had been made to prepare time-varying embedded cost studies.

The National Association of Regulatory Utility Commissioners published its *Electric Utility Cost Allocation Manual* in 1992. That handbook provided explicit guidance on some of the different methods that regulators used at that time to apportion rates for both embedded cost and marginal cost frameworks. It was controversial from the outset, due to omission of a very common method of apportioning distribution costs — the basic customer method. However, it is the most recent, comprehensive and directly relevant work on cost allocation prior to this manual.

4 Simplified from principles attributed to Henry Herz, consulting economist, cited in Garfield and Lovejoy (1964, pp. 163-164).

2. Main Elements of Rate-Making

The process of setting rates varies significantly among states and different types of utilities, such as investor-owned utilities regulated by state utility commissions and self-regulated **municipal** and **cooperative utilities**. However, the most basic and essential elements are typically the same. The discussion in this chapter focuses on the methods used for IOUs, with occasional notes on distinctions in other contexts.

There are three distinct elements, or phases, in a rate case, and each phase feeds into the next. The first determines the required level of annual revenue, typically known as the revenue requirement. The second phase, the primary subject of this manual, apportions the revenue requirement among a small number of customer classes, traditionally with additional distinctions made between customer-related costs, demand-related costs and energy-related costs. Finally, the individual prices, formally known as **tariffs** or rates,[5] are designed in order to collect the assigned level of revenue from each class. These elements can be considered by the regulator at the same time or broken into separate proceedings or time schedules. Regardless, the analysis is inevitably sequential. This chapter ends with a brief description of the key features of the procedure used in rate cases.

2.1 Determining the Revenue Requirement

The revenue requirement phase of a conventional rate case consists of determining the allowed **rate base**, allowed **rate of return** and allowed operating expenses for the regulated utility on an annualized basis. In most jurisdictions, the annualized revenue requirement is developed for a "**test year**," which is defined as either a recent year with actual data, which may be adjusted for known changes, or projections for a future year, often the period immediately after the expected conclusion of the rate case. A few elements of the revenue requirement phase have important bearing on the cost allocation study, and we address only these.[6]

Many regulated utilities in the modern United States are one corporation within a broader holding company, which may include other regulated utilities or other types of corporate entities. Early in the revenue requirement process, the utility must identify the subset of costs relevant to the regulated operations that are the subject of a rate case and separate those costs from other operations and entities. This is generally called a jurisdictional allocation study. It is likely that a holding company that has both regulated and unregulated activities has some activities that are of a fundamentally different nature and level of risk from the operations of the regulated utility in question, where sales and revenues can be relatively stable. Jurisdictional allocation is generally beyond the scope of this manual, but many of the principles for apportioning costs among classes may also be relevant for apportioning those costs among multiple states served by a single utility or utility holding company.

Within the subset of costs identified by the regulated utility, the regulator has the discretion to disallow certain costs as imprudent or change key parameters used by the utility to determine the overall revenue requirement. Disallowance of major costs, such as investments in power plants that were not completed or did not perform as expected, have occurred and have led to the bankruptcy of a utility in at least one case.[7] Smaller disallowances or adjustments are more common, such as a reduction in the allowed rate of return the utility proposes, as well as common disallowances for advertising and executive or incentive compensation, which would lower the revenue requirement commensurately.

5 This is an important difference between British English, where "rates" refers to property taxes, and American English, where the term means retail prices.

6 For a more detailed discussion of the determination of the revenue requirement, see Chapter 8 of Lazar (2016).

7 This was the Public Service Company of New Hampshire and the Seabrook nuclear plant (Daniels, 1988).

Performance-based regulation (PBR) may divert from the strict cost accounting approach of the conventional rate case, relying on the performance of the utility to meet goals set by the regulator as a determinant of all or a portion of the revenue requirement.[8]

At the end of this phase, the regulated utility has been assigned a certain level of revenue that it is expected to be able to collect in the **rate year** following the end of the rate case. This annualized revenue requirement is passed along to the next step in the process.

2.2 Cost Allocation

In the second phase of a rate case, the overall revenue requirement is divided up among categories of utility customers, known as classes. These customer classes are usually quite broad and can contain significant variation but are intended to capture cost differentials among different types of customers. Some utilities have many customer classes, but typical classes for each utility include residential customers, small business customers, large commercial and industrial (C&I) customers, irrigation and pumping, and street lighting customers.

At this stage in the process, the utility will use different types of data it has collected to assign costs to each customer class. The types of data available have changed over time, but historically these have included energy usage in specific time periods, different measures of demand, the number of customers in each class and information on generation patterns. In addition, utility costs are categorized using a tracking system known as the Uniform System of Accounts. This system was established by the Federal Power Commission — now the **Federal Energy Regulatory Commission** (FERC) — around 1960, leading to the shorthand of "FERC accounts." Further detail is provided in Appendix A.

These data will be used in a cost of service study that attempts to equitably divide up the revenue requirement among the rate classes. There are two major categories in these studies: an embedded cost of service study (or fully allocated cost of service study), which focuses on the costs the utility intends to recover and other metrics for one year; and a marginal cost of service study, which estimates the responsibility of customer classes for system costs in the future.

An embedded cost of service study itself typically has three major steps:

1. Functionalization of costs as relevant to generation, transmission, distribution and other categories, such as billing and customer service and administrative and general costs.
2. Classification of costs as customer-related, demand-related or energy-related.
3. Allocation among rate classes.

An embedded cost of service study directly splits up the revenue requirement, which is itself calculated on an embedded cost basis.

A marginal cost of service study has a different structure. It begins with a similar functionalization of costs, separately analyzing generation, transmission and distribution. The next step is the estimation of marginal unit costs for different elements of the electric system and customer billing. The estimated marginal costs are then multiplied by the billing determinants for each class. This produces a class marginal cost revenue requirement; when combined with other classes, it's a system MCRR. However, revenue determination solely on this marginal cost basis typically will be greater or less than the allowed revenue requirement, which is normally computed on an embedded cost basis. It is only happenstance if the MCRR is the same as, or even similar to, the revenue requirement calculated on an embedded cost basis. As a consequence, the results of a marginal cost of service study must be reconciled to recover the annual revenue requirement.

Although both embedded and marginal cost studies include precise calculations, most regulators are not strictly bound by the results. Numerous other factors are involved in cost allocation for each rate case, including gradualism of rate changes, policy considerations, such as anticipated changes, and economic conditions in the service territory. The data developed for cost allocation and the analytical techniques used in the cost of service studies can provide helpful information for other purposes, such as rate design. Careful attention

8 For an example of a framework that divorces utility earnings from utility investment, see Lazar (2014). For a broader discussion of performance-based regulation, see Littell et al. (2017).

must be paid, however, to the reason the data were developed, and caution must be taken so that this information is used constructively in an appropriate manner.

The final allocation of costs among the rate classes, as well as the other relevant data and analysis, is passed on to the next step in the process.

2.3 Rate Design

The rate design phase of a proceeding is sometimes separated in time from the previous phases so the parties know the revenue amounts that each class is expected to contribute, or it may be combined into a single proceeding with the other two phases. This manual does not address rate design principles in detail, but they are addressed in two companion publications by RAP: *Smart Rate Design for a Smart Future* (Lazar and Gonzalez, 2015) and *Smart Non-Residential Rate Design* (Linvill, Lazar, Dupuy, Shipley and Brutkoski, 2017). Related issues around compensation for customers with distributed generation are also addressed in RAP's *Designing Distributed Generation Tariffs Well* (Linvill, Shenot and Lazar, 2013).

At the highest level, the principles used for rate design are significantly different from those for cost allocation. Rate design should always focus on forward-looking efficiency, including concepts like long-run marginal costs for the energy system and societal impacts more generally, because rate design will influence consumer behavior, which in turn will influence future costs.

Rate design decisions also include principles around understandability and the ability of customers to manage their bills and respond to the price signals in rates. Of course, equity is also a consideration in the rate design process, but in a significantly different context: Primarily, it's concerned with the distribution of costs among individual customers within a rate class.

There are three basic rate components:

1. **Customer charges**: fees charged every billing period that generally do not vary with respect to any usage characteristics.
2. **Volumetric energy charges**: prices based on metrics of kWh usage during the billing period.
3. **Demand charges**: prices based on metrics of kW or **kilovolt-ampere** (kVA) power draw during the billing period.

These three basic options allow for a wide range of variations based on season, time of day and type of demand measurement. All types of rates can vary from season to season or month to month, often based on either the cost of service study or energy market conditions.[9] Both demand charges and **energy charges** measure the same thing: electricity consumption over a period of time. Even though demand charges are typically denominated in kWs as a measurement of power draw, virtually all demand charges are actually imposed on consumption within short windows, often the highest 15-, 30- or 60-minute window during the billing period.[10] Because it is based on the maximum within those short windows, a demand charge effectively acts as a one-way ratchet within a billing period. Additional ratchets can be imposed over the course of the year, where the demand charge may be based on the greater of either billing period demand or 90% of the maximum demand within the previous year. In contrast, energy charges are based on consumption throughout a billing period, with no ratchets. Energy charges can vary by time within a billing period, generically known as time-varying rates.[11] Common variants include **time-of-use** (TOU) energy charges, where prices are set separately for a few predetermined time windows within each billing period; and **critical peak pricing**, where significantly higher prices are offered for a short time period announced a day or two in advance in order to maximize customer response to events that stress the system.

Some rate analysts propose rates that rigorously follow the results of a cost allocation study, meaning that customer-related costs must be recovered through customer charges and demand-related costs must be recovered through

9 Rates that vary by season are often referred to as seasonal rates. However, some utilities also define "seasonal" customer classes for customers who have a disproportionate share of their usage during a particular time period. Rates for seasonal customer classes may also be referred to as seasonal rates, which can cause confusion.

10 Note that in these cases kWs is a simplified description of kWhs per hour since it is not truly an instantaneous measurement.

11 Some analysts may describe certain types of demand charges as time-varying rates as well, such as those that are imposed only within certain time windows (e.g., 2 to 6 p.m. on nonholiday weekdays).

demand charges. However, most analysts do not and are careful to note that categorizations like "demand-related" are simplifications at best and, as this manual details, generally reflect an increasingly obsolete framework. Forward-looking efficiency is not a feature of embedded cost of service studies and additionally may require consideration of broader **externalities** that are not necessarily incorporated in the revenue requirement. Similarly, rate design must consider customer bill impacts and the related principles of understandability, acceptability and customer bill management.

2.4 Rate Case Procedure

Although procedures at state utility commissions vary greatly, there are typically several common elements. Most rate cases begin with a proposal from the regulated utility. In the most formal terms, a utility commission is adjudicating the rights, privileges and responsibilities of the regulated utility, although typically without the full formalities and rules of a judicial proceeding. Other interested parties are allowed to become intervenors to participate in discovery, present witnesses, brief the issues for the commission and potentially litigate the result in court. This process often automatically includes an official state consumer advocate. A wide range of stakeholders may join the process, including large industrial consumers, chambers of commerce, low-income advocates, labor, utility investors, energy industries and environmental advocates. These non-utility parties can critique the utility proposal and can propose alternatives to utility cost allocation methods as well as other substantive elements of the rate case. Rate cases can be resolved through a final decision by the utility commission based on the record presented, or some or all aspects of a rate case can be resolved through a settlement among the various parties.

The costs of a rate case for the regulated utility are considered part of the cost of service and ultimately become part of the revenue requirement determined in the rate case. Many states make explicit funding arrangements for the commission itself and any state consumer advocate, often ultimately recovered from ratepayers. In some states and most Canadian provinces, ratepayer funding was historically given to other intervenors who participated productively in the process, a practice that continues in California. However, it is much more common for stakeholders to bear the burden of any litigation costs, which limits the ability of many stakeholders to advance their interests at this level.

3. Basic Components of the Electric System

The electric utility system, for general descriptive purposes and for regulatory and legal purposes, typically is divided into several categories of activities and costs, including generation, transmission, distribution, billing and customer service, and A&G costs. In a vertically integrated utility, a single entity owns and operates all of these, although many other forms of market structure and ownership exist in the United States. Each of these segments includes capital investments and labor and nonlabor operating expenses. Each of these segments is operated and regulated according to different needs and principles.

These distinctions at each level of the power system are important to cost allocation, and the terminology is important to understand. Many of the arguments about proper allocation of costs hinge on the purpose for, and capabilities of, capital investments and the nature of operating expenses. Thus, having a correct understanding of the purpose, limitations and current usage of each major element of the system is important to resolve key cost allocation questions. Figure 7 is a diagram of a traditional electric power system, with one-way power flow from a large central generation facility through the transmission and distribution system to end-use customers (U.S.-Canada Power System Outage Task Force, 2004).

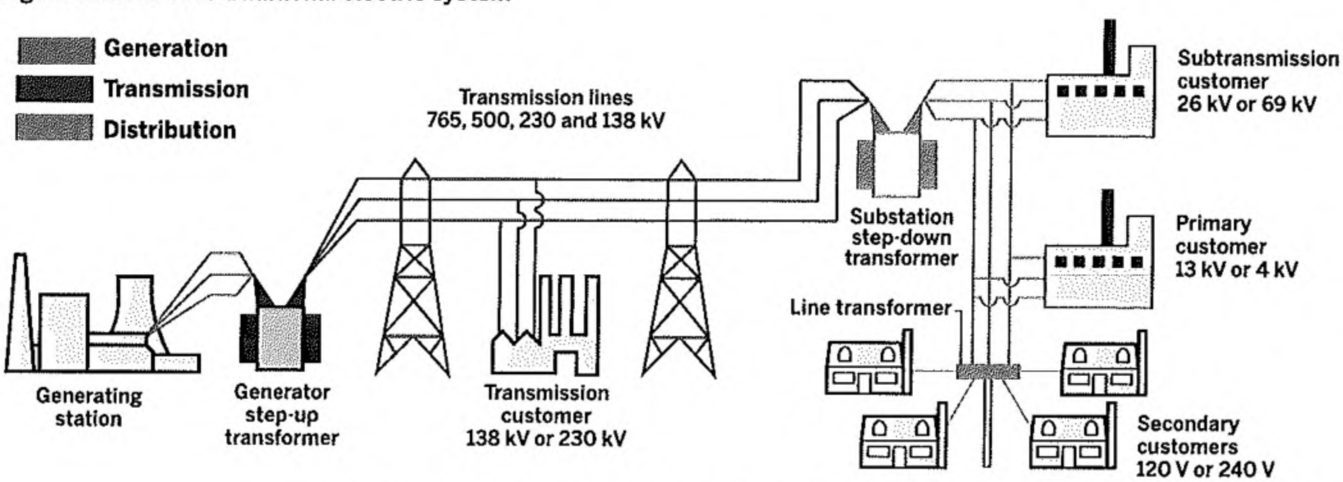
The evolving electric grid will be much different from the grid of the past hundred years. The "smart grid" of the future will look different, operate differently and have different cost centers and potentially different sources of revenues. As a result, it will need different cost allocation methods. Figure 8 on the next page shows a vision of the direction the electric system is evolving, with generation and storage at consumer sites, two-directional power flows, and more sophisticated control equipment for customers and the grid itself (U.S. Department of Energy, 2015).

This manual discusses many of the changes underway in the electric system, but undoubtedly the future will bring further change and new challenges.

3.1 Categories of Costs

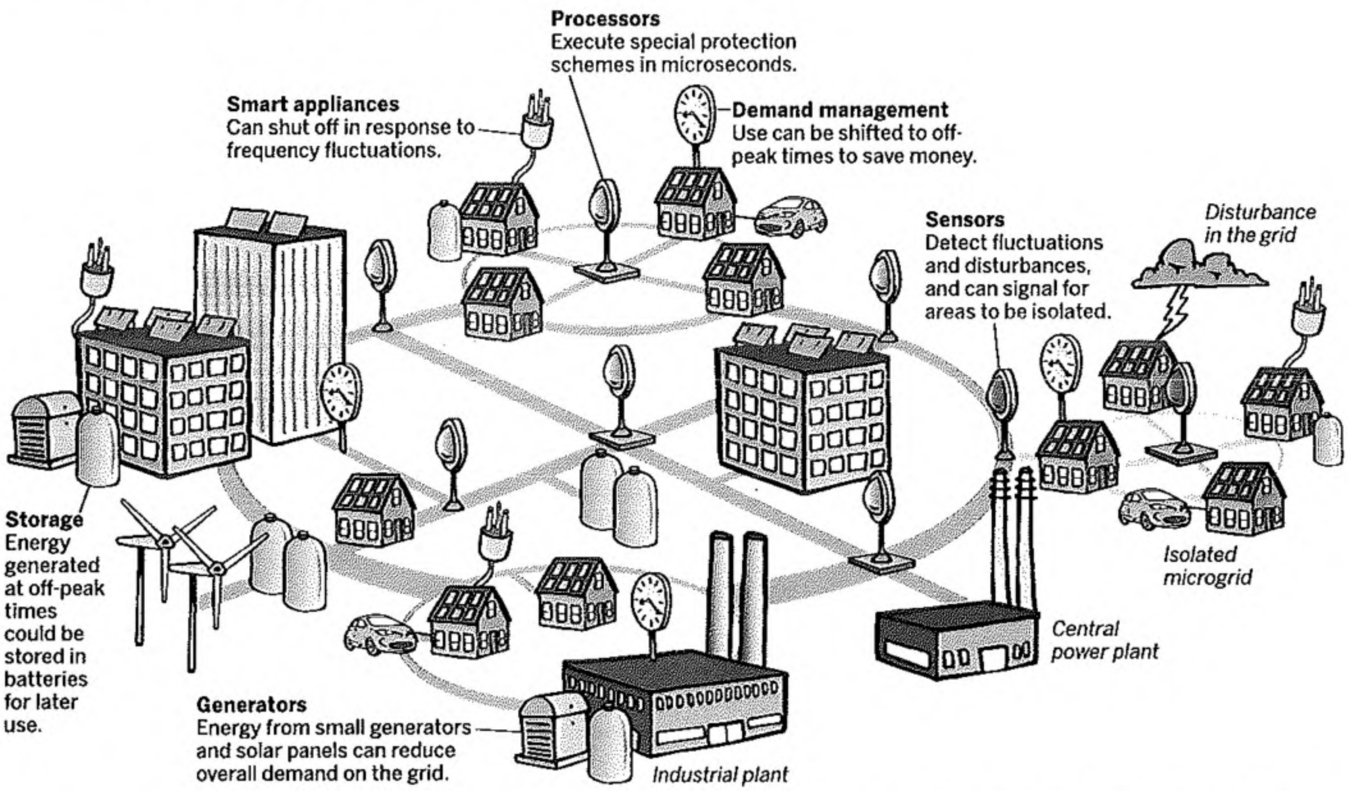
All decisions that a utility makes have consequences for its overall cost of service. Some of those decisions were made decades ago, as the utility made investments — including large power plants and office buildings — based on conditions

Figure 7. Illustrative traditional electric system



Source: Adapted from U.S.-Canada Power System Outage Task Force. (2004). *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*

Figure 8. Illustrative modern electric system



Source: Adapted from U.S. Department of Energy. (2015). *United States Electricity Industry Primer*

or forecasts at that time. Some of the decisions are made every day, as the utility dispatches power plants or replaces worn-out distribution equipment. Many of the decisions that determine the utility's revenue requirement — such as the historical decisions to build particular power plants in particular locations — result from complex processes involving past expectations and many practical complications and trade-offs.

3.1.1 Generation

Electricity generation[12] comes from many different types of technologies that utilize many different types of fuels and resources. Most types of steam-electric units burn fuel, which can be oil, coal, natural gas, biomass or waste products, in a boiler to produce steam to turn a turbine. This turbine then turns an electric generator. Most steam units are older and generally limited in their ability to cycle on and off. This means they can only change generation levels slowly and may require many hours to start up, shut down and restart.

Some noncombustion technologies use a steam turbine to generate electricity. Some geothermal units use steam to drive a turbine, using heat transferred up from underground to boil water. Concentrated solar power, or solar thermal, uses heat from the sun to boil water and spin a turbine. Nuclear generation also uses a steam turbine, where the heat to boil water comes from a chain reaction of uranium fission.

Combustion turbines, which are similar to jet engines, use heated gases from the combustion of either a liquid or gaseous fuel to directly spin a turbine and generate electricity. Simple cycle combustion turbines directly exhaust a significant amount of heat. Combustion turbines can be turned on and off very quickly and require high-quality, relatively clean fuels because of the contact between the combustion gas and the turbine blades.

12 Some sources, including the FERC accounts and the 1992 NARUC *Electric Utility Cost Allocation Manual*, use the term "production" instead of "generation." This manual uses the term "generation" and generally includes exports from storage facilities under this category.

Combined cycle units include combustion turbines but capture the waste heat to boil water, produce steam and spin an extra turbine to generate electricity. As a result, combined cycle units have higher capital costs than combustion turbines but generate more electricity for each unit of fuel burned.

Hydroelectric plants use moving water, either released from reservoirs or running in rivers, to spin turbines and generate electricity. These units vary widely in their seasonal generation patterns, storage capacity and dispatchability. Many, but not all, hydroelectric plants are easily dispatchable to follow load but may be constrained by minimum and maximum allowed river flows below the facility.

There are also a variety of noncombustion renewable resources, including wind power, solar photovoltaic (PV), solar thermal and potentially tidal and current power. In addition, fuel cells can generate electricity from hydrogen by using a chemical reaction. The only byproduct of a fuel cell reaction is water, but different methods of producing hydrogen can have different costs and environmental impacts.

Power supply can come from different types of energy storage facilities as well, although most of these resources also consume electricity. Traditional types of storage, such as pumped hydroelectric storage (where water is moved to higher ground using electricity at times of low prices and released back down to spin turbines at times of high prices) and flywheels have been around for many decades, but battery storage and other new technologies are becoming more prevalent. Different types of storage technologies can have very different capabilities, varying from a few minutes' worth of potentially exportable energy to a few months' worth, which determines the types of system needs that the storage can address. As a result, the allocation of these costs requires careful attention by the cost analyst.

Each of these technologies has a different cost structure, which can depend on the type of fuel used. This is typically divided among: (1) upfront investment costs, also known as capital costs; (2) **operations and maintenance (O&M) costs**, which may depend on the numbers of hours a facility generates ("dispatch O&M costs") or can be incurred regularly on a monthly or annual basis ("nondispatch O&M costs"); and (3) fuel costs. Fuel costs per unit of energy generation depend on the price of the fuel consumed and the efficiency of the unit; this is often defined as an efficiency percentage comparing input fuel potential energy to output electric energy, or as a **heat rate** defined as the **British thermal units** (Btu) of fuel input for every kWh of output electric energy.

Dirtier fuels, such as coal and oil, require expensive and capital-intensive pollution control equipment. Different costs are also incurred in the delivery and handling of each fuel prior to its use, as well as the disposal of any byproducts. For example, both coal ash and nuclear waste require disposal, and there are different controversies and costs associated with each. Noncombustion renewable resources have very low variable costs and relatively high capital costs. Storage resources generally have high investment costs, moderate maintenance costs and low operating costs. The decision around their dispatch is defined by the opportunity cost of choosing the hours to store and discharge, with the goal of picking the hours with the greatest economic benefit.

Some plants, mainly steam, combustion turbine and combined cycle, can be set up to use more than one fuel, primarily either natural gas or oil. Such a dual fuel setup involves a range of costs but allows the plant operator to choose the fuel that is less expensive or respond to other constraints.

Generation facilities are frequently categorized by their intended purpose and other characteristics. This terminology is evolving and does not necessarily reflect a permanent condition. For example, several types of units traditionally have been characterized as baseload because they are intended to run nearly all the time. This includes most steam-electric combustion units, particularly those run on coal. This also includes nuclear units, which run nearly all of the time with the exception of long refueling periods every few years that can last for months. Historically, **baseload units** had higher capital costs, which could be offset by lower fuel costs given their ability to run constantly. However, as fuel price patterns have changed, this is not always the case, particularly when natural gas is cheaper than coal.

Several types of plants are characterized as **peakers** or peaking units because they are flexible and dispatched easily at times of peak demand. Combustion turbines are the prime example of a peaking unit. Historically, these units had lower capital costs per unit of capacity and higher fuel costs per kWh generated. Again, this may no longer be true as fuel prices have changed.

Plants that are neither baseload nor peaking units are often referred to as **intermediate units**. They run a substantial portion of the year but not the whole year or just peak hours. "Midmerit" and "cycling" are commonly used synonyms for these types of generators. Over the last two decades, natural gas combined cycle facilities often filled this role in many parts of the country, but changing fuel costs and environmental regulations have altered the typical operating roles of many types of generation.

Hydroelectric units may effectively be baseload resources or may be storage reservoirs that allow generation to be concentrated in high-value hours. Other noncombustion renewable resources are often characterized as variable or **intermittent resources** because these technologies can generate electricity only in the right conditions — when the sun is shining, the wind is blowing or the currents are moving. However, the addition of storage to these facilities can make these characteristics much less relevant. In addition, the accuracy of forecasts for these resources has improved greatly. These variable renewable resources can also be operated in certain ways to respond to electric system or market conditions, such as through **curtailment**.

3.1.2 Transmission

Transmission systems comprise high-voltage lines, over 100 **kilovolts** (kV), that are generally carried via large towers (although sometimes on poles or buried underground) and the **substations** that interconnect the transmission lines both to one another and between generation resources and customers. Subtransmission lines that interconnect distribution substations, operating between 50 kV and 100 kV, may be functionalized as distribution plant.

Utilities use a variety of transmission voltages. A higher voltage allows more power to be delivered through the same size wires without excessive **losses**, overheating of the **conductor** (wire) or excessive drop in the operating voltage over the length of the line. Higher voltages require taller towers to separate the power lines from the ground and other objects and better insulation on underground cables but are usually less expensive than running multiple conductors at lower voltages where large amounts of power need to be delivered.

Transmission systems can also be either **alternating current** (AC) or **direct current** (DC). Some transmission using DC has been built because it can operate at high voltages over longer distances with lower losses; these lines are known as **high-voltage direct current** (HVDC). However, the vast bulk of the transmission system in the United States is AC.

Transmission serves many overlapping functions, including:

- Connecting inherently remote generation (large hydro, nuclear, mine-mouth coal, wind farms, imports) to load centers.
- Allowing power from a wide range of generators to reach any distribution substation to permit least-cost economic dispatch to reduce fuel costs.
- Providing access to neighboring utilities for **reserve** sharing, economic purchases and economic sales.
- Allowing generation in one area to provide backup in other areas.
- Reducing **energy losses** between generation sources and the distribution system, where transmission capacity is above the minimum required for service.

Each of these purposes carries different implications for cost allocation. Some transmission is needed in all hours, while other transmission is built primarily to meet peak requirements.

Transmission substations connect the generators to the transmission system and the various transmission voltages to one another. They also house equipment for switching and controlling transmission lines. Most substations are centered on large **transformers** to convert power from one voltage to another. The largest customers, such as oil refineries, often have their own substation and take delivery from the grid at transmission voltage.

3.1.3 Distribution

Distribution substations and lines are required for the vast majority of customers who take service at the distribution level. The distribution system receives power primarily from the transmission system through distribution substations, which convert power from higher transmission-level voltages down to distribution-level voltages. Some power may be delivered to the distribution system directly from small generators, such as small hydro plants and distributed generation. Distribution substations are smaller versions of transmission substations.[13] These are often connected by subtransmission lines, which may be functionalized as either transmission or distribution in cost studies. Collectively, the transmission and distribution systems are referred to as T&D or as the delivery system.

From each substation, one or more distribution feeders operating between 2 kV and 34 kV, known as **primary voltage** lines, run as far as a few miles, typically along roadways. These are mostly on wooden utility poles shared with telephone and cable services or in underground conduit. A single pole or underground route may carry multiple circuits. Each feeder may branch off to serve customers on side streets. Although distribution feeders leaving the substations are usually three-phase, like the transmission lines, branches that do not carry much load may be built as single-phase lines with just two wires.

Some customers take power directly at primary voltage (usually 2 kV to 34 kV) and transform it down within their premises to a **secondary voltage** (600 **volts** or less) or use it directly in high-voltage equipment. All residential and most commercial customers take service at secondary voltages, which typically range from 120 V to 480 V. For that purpose, the utility must provide **line transformers**, which are the large cylinders on some utility poles for overhead distribution and the ground-mounted metal boxes near buildings for underground distribution. There is a frequently used shorthand in which customers served at primary voltage are referred to as primary customers and any customer classes distinguished on this basis are described as primary — for example, primary **general service** or primary commercial. Similarly, customers served at secondary voltage can be described as secondary customers, and customer classes distinguished on that basis are referred to as secondary — for example, secondary general service or secondary commercial.

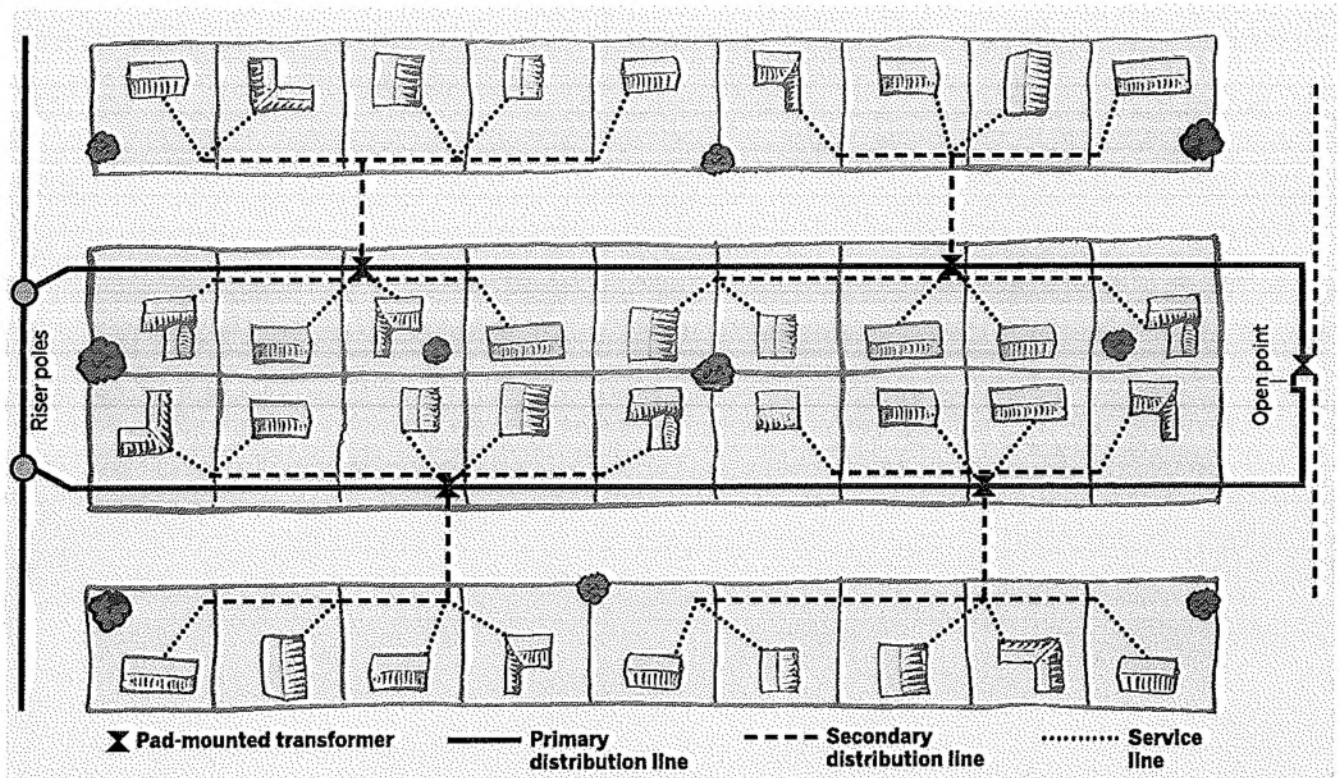
In urban and suburban settings, a typical transformer will serve several residential customers or small businesses, either in one building or several buildings that are relatively close to one another. Typically, an apartment building is served by a larger transformer than would serve single-family dwellings, but the transformer or multitransformer installation could serve dozens or even hundreds of customers. A single large secondary customer is usually served by one or more dedicated transformers, and in exurban and rural areas even a relatively small customer may be so far away from neighbors as to require a dedicated transformer.

Some secondary voltage customers will be served directly by a **service line** from the transformer to their buildings. Other customers farther up the road will be fed from a secondary distribution line from a nearby transformer that is attached to the same poles as the primary feeder but lower down. Secondary voltage lines in older neighborhoods served with overhead wires are often networked among several transformers. For many utilities, underground secondary lines in modern neighborhoods generally are not networked. Underground service is generally more expensive than overhead service but often required by local regulations for aesthetics or reliability reasons.

Figure 9 on the next page illustrates one relatively common arrangement. In this example, each transformer serves two houses directly with service lines, and feeds secondary lines from which service lines run to two or three other houses on the same side of the street and four or five houses across the street. The illustration is for an underground system. The basic layout of an overhead system would be similar. However, since it is easier to string overhead service lines across the street than to dig lines under the street, service lines might run directly from an overhead transformer to one or two houses across the street, and the secondary might just run on the transformers' side of the street, with service lines crossing the street to additional customers. The key factor here for cost allocation purposes is that even secondary voltage lines are often shared among multiple customers and are not a direct cost responsibility of any one of them individually.

13 In some cases, a higher-voltage distribution line (e.g., 13 kV) may power a lower-voltage line (e.g., 4 kV) through a substation.

Figure 9. Underground distribution circuit with radial secondary lines



Note: Overhead primary lines run down the riser poles and go underground.

Figure 10 shows a portion of a similar distribution circuit but highlights the difference that in this case the secondary lines are networked, meaning power can flow to the relevant customers over both transformers simultaneously. This allows each transformer to serve as backup for the others in that network and allows for more flexible operation to minimize losses and prevent overloads.

Figure 10. Detail of underground distribution circuit with networked secondary lines

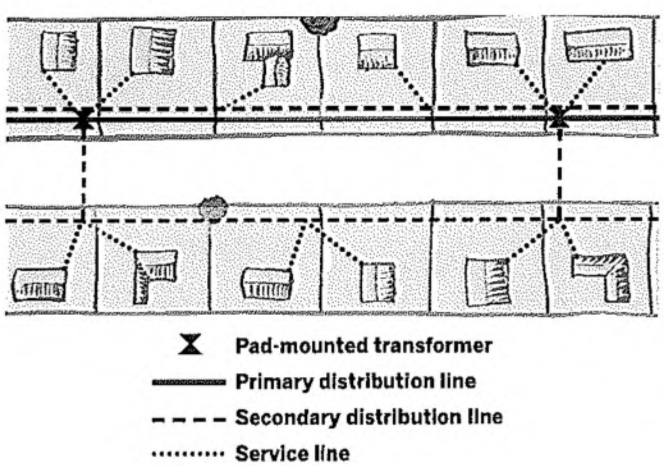


Figure 11 on the next page illustrates a typical overhead distribution pole, showing the primary lines, a transformer, an electric service to one home and secondary lines running in both directions to serve multiple homes.

The final step in the delivery of power from the utility to the customer is the service line, or drop,[14] from the common distribution facilities in the public right of way to the customer's meter. That line may be overhead or underground. Even where the distribution service is overhead, customers may be served by an underground service drop out of concerns for aesthetics or reliability, since underground lines are not vulnerable to damage from wind or trees.

For primary voltage customers, the service drop is a line at the primary voltage, attached to one or more phases of primary feeder. For secondary customers, the service drop may run from the transformer to the customer or from a convenient point along the secondary lines.

14 Since overhead service lines often slope down from their connection on the utility pole to the attachment point on the customer's building, they tend to literally "drop" the service down to the customer.

Figure 11. Secondary distribution pole layout

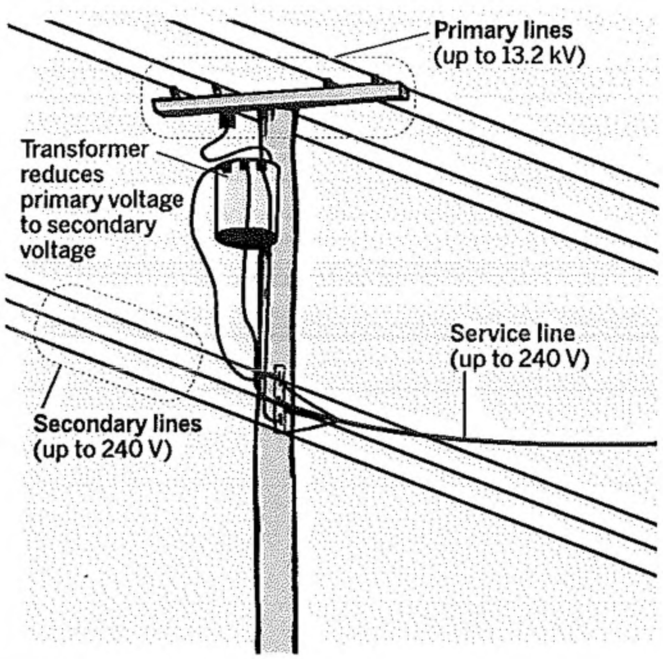
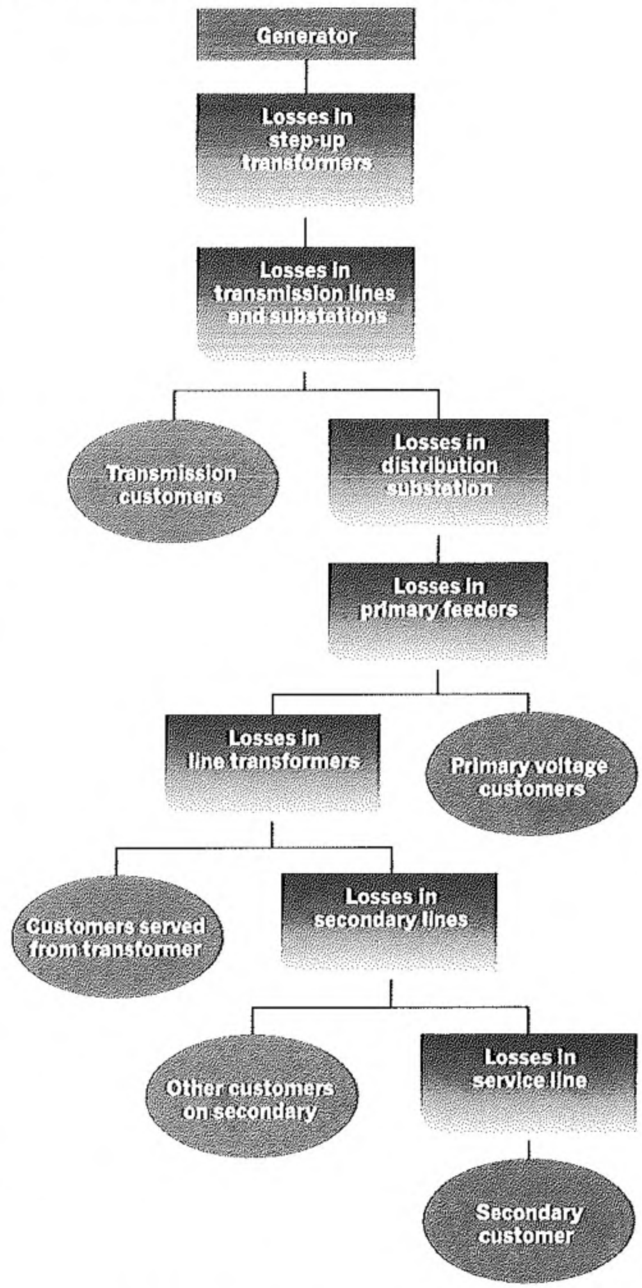


Figure 12. Electric delivery system line losses



3.1.4 Line Losses

For most purposes in a cost allocation study, line losses are not broken out as a separate category of costs. However, the physics of energy flowing over transmission and distribution lines can lead to nontrivial costs. A line loss study is an important input into a cost of service study because it helps determine the differential cost allocations to customers served at different voltages.

A small percentage of power is lost in the form of heat as it flows through each component of the delivery system, as discussed at length in Lazar and Baldwin (2011). The losses in conductors, including transmission and distribution lines, are known as resistive loss. Resistive loss varies with the square of the quantity of power flowing through the wire. Because of this exponential relationship between load and losses, a 1% reduction in load reduces resistive losses by about 2%. The levels of conductor losses from the generators to a customer at secondary voltage (such as a residential customer) are illustrated in Figure 12. Transformers have more complex loss formulae because a certain amount of energy is expended to energize the transformer (core losses) and then all energy flowing through the transformer is subject to resistive losses. Average annual line losses typically are around 7%, but marginal losses can be much higher, more than 20% during peak periods (Lazar and Baldwin, 2011, p. 1).

Reducing a customer's load (or serving that load with an on-site generation or storage resource) reduces the losses in the service drop from the street to the customer, the secondary line (if any) serving that customer, the line transformers, the distribution feeder, the distribution substation, and transmission lines and transmission substations. Lower loads, on-site generation and storage also reduce the generation capacity and reserve requirements, meaning that a 1-kW reduction in load at the customer's premises can avoid nearly 1.5 kWs of generating capacity at a central source (Lazar and Baldwin, 2011, p. 7).

3.1.5 Billing and Customer Service

Traditionally, metering is considered a customer-specific expense for the purpose of billing. Advanced metering infrastructure is used for a much wider array of purposes, however, such as energy management and system planning. This indicates that broader cost allocation techniques should be used. Historically, meter reading was a substantial labor expense, with meter readers visiting each meter every billing cycle to determine usage. However, utilities with either AMI or AMR technology have either eliminated or greatly reduced the labor expenses involved. Customers that opt out of AMI often incur special meter reading costs, if meter readers are needed for a small number of customers.

Most utilities bill customers either monthly or bimonthly for a variety of related practical reasons. If customers were billed less frequently, the bills for some customers would be very large and unmanageable without substantial planning. If billed more frequently, the billing costs would be significantly higher. Billing closer to the time of consumption provides customers with a better understanding of their usage patterns from month to month, which may help them increase efficiency and respond to price signals. There are exceptions, since many water utilities, sewer utilities and even a few electric utilities serving seasonal properties may render bills only once or twice a year.[15]

Related to billing and metering, there are a range of investments and expenses needed to store billing data and issue bills. Historically, billing data was quite simple, and the cost of issuing bills was primarily printing and mailing costs. With AMI, billing data has grown substantially more complex, and additional system and cybersecurity requirements are needed. Conversely, online billing can lower certain costs and provide easier access to customer data.

The expenses of unpaid bills are known as uncollectibles and typically are included as an adjustment in the determination of the revenue requirement as a percentage of expected bills in order to keep the utilities whole. Bills may go unpaid because of customer financial difficulties, departure from the service territory or any number of other factors. In some jurisdictions, deposits are required to protect utilities from unpaid bills. Utilities often use their ability to shut off electric service to a customer to ensure bill payment, and many jurisdictions implement shutoff protections to ensure that customers are not denied access to necessary or life-preserving services.

Customer service spans a whole range of services, from answering simple questions about billing to addressing complex interconnection issues for distributed generation. These expenses may vary greatly by the type of customer. Many utilities have "key accounts" specialists who are highly trained to meet the needs of very large customers. Large customers typically have more complex billing arrangements, such as campus billing, **interruptible rates** and other elements that require more time from engineering, legal and rate staff, as well as higher management. Some utilities lump these customer services together. The better practice is to keep them separate based on how each rate class incurs costs and benefits from the expenses.

Some utilities also characterize various public policy programs, such as energy efficiency programs, as customer service, but this is typically a mistake because these costs are not related to the number of customers. Instead, they relate to the power supply and delivery system capacity and energy benefits the programs provide.

Some states allow utilities to include general marketing and advertising efforts in rates, but others require shareholders to fund any such efforts. More narrowly targeted energy conservation and safety advertising expenses are often recovered from ratepayers as a part of public policy programs.

3.1.6 Public Policy Program Expenditures

States have mandated that utilities make expenditures for various public policy purposes. One of the largest is energy efficiency, but others include pollution control, low-income

15 This is also the case for California customers who opt out of AMI (California Public Utilities Commission, 2014).

customer assistance, renewable resources, storage and hardening of the system to resist storm damage. Each of these cost centers has a place in the cost allocation study, and each must be treated based on the purpose for which the cost is incurred.

3.1.7 Administrative and General Costs

Utilities also have a wide variety of overhead costs, typically called administrative and general costs. They include necessary capital investments, known as general plant, and ongoing expenses, typically called A&G expenses. General plant includes office buildings, vehicles and computer systems. A&G expenses include executive salaries, pensions for retired employees and the expenses due to regulatory proceedings. The common thread is that these costs support all of a utility's functions.

3.2 Types of Utilities

Utilities differ in terms of ownership structure and the types of assets they own. The many types of electric utility organizations have different characteristics that may lead to different cost allocation issues and solutions. Nationwide, publicly owned utilities typically have lower rates. In 2016, the average residential customer served by public power paid 11.55 cents per kWh, compared with 11.62 cents for co-ops and 13.09 cents for customers served by investor-owned utilities, reflecting a mix of service territory characteristics and differing sources of electricity, costs of capital and tax burdens (Zummo, 2018). Some utilities are also vertically integrated, owning generation, transmission and distribution assets simultaneously, while others own just distribution assets.

3.2.1 Ownership Structures

Investor-owned utilities serve about 73% of American homes and businesses and own about 50% of electric distribution circuit miles (National Rural Electric Cooperative Association, 2017). The regulated utilities that directly serve customers may be part of larger holding companies that include other corporate assets, such as regulated utilities in other states, natural gas assets or totally unrelated enterprises. Unlike utilities owned by governments or by the members and customers, IOUs include a return on investment, specifically a return on equity for shareholders, in the calculation of the revenue requirement. This is typically calculated as the net rate base (gross plant net of accumulated depreciation) multiplied by the weighted average rate of return, which is composed of the interest rate on debt and the allowed return on equity. In many states, utility commissions regulate only IOUs.

Publicly owned utilities — including municipal utilities, or munis, and public power districts — serve about 15% of American homes and have about 7% of electric distribution circuit miles (National Rural Electric Cooperative Association, 2017). Many of the areas served are urban, and municipal utilities often provide other services as well, such as water, sewer and natural gas. These utilities evolved for a variety of reasons but typically are not subject to state or federal income tax (but typically pay many other types of taxes) and do not include a return on equity in rates. For this reason, their rates tend to be lower than those of most IOUs. The state or local governmental entity that sets up this type of utility also determines the governing structure for the utility, which could be an elected or appointed board. Typically this board will hire a professional manager to oversee the utility. Many municipal utilities also determine their annual revenue requirement on a cash flow basis, which can lead to greater annual variability. In most cases, state public utility commissions have little or no authority over munis and public power districts.

Electric cooperatives are nonprofit membership corporations or special purpose districts that provide service to about 12% of Americans and own about 42% of electric distribution circuit miles (National Rural Electric Cooperative Association, 2017). They also serve more than half of the land area in the U.S. They mostly serve areas that IOUs originally declined to serve because expected sales did not justify the cost, given their shareholders' expectations for rates of return and the required investment. Some cooperatives still serve thinly populated rural areas with few large loads. Others have seen their service territories transformed to booming suburbs or industrial hubs. These entities are also exempt from federal and state income tax and do not need to include a return on equity in the revenue requirement. Unlike municipal utilities, however, cooperatives cannot issue tax-exempt debt. Cooperatives do have flexibility to offer other services to their customers, such as broadband internet, appliance sales and repair, and contract billing and collection. Many cooperatives operate in areas with limited alternatives, and they tend to have good relationships with their member customers. An increasing number of electric cooperatives are building on these assets by entering the solar installation and maintenance field. In most states, cooperatives are entirely self-regulated, with a board being elected by the members. About 16 states regulate cooperatives, often less rigorously than they regulate IOUs (Deller, Hoyt, Hueth and Sundaram-Stukel, 2009, p. 48). This is because any "profits" remain with the member-owned cooperative and members can affect decision-making through board elections.

3.2.2 Vertically Integrated Versus Restructured

Vertically integrated utilities have very different cost structures than utilities in states where the electricity industry has been restructured. Vertically integrated utilities provide complete service to customers, including generation, transmission and distribution service, and their mix of resources and cost elements can be extensive. Generation costs may include utility-owned resources, long-term contract resources, short-term contract resources, storage resources, and spot market purchases and sales. Transmission costs may include resources that are utility-owned; jointly owned with other utilities; owned by transmission companies purchased on a short-term or long-term basis; or purchased through long-term arrangements with an **independent system operator** (ISO), **regional transmission organization** (RTO), federal power marketing agency (e.g., the Bonneville Power Administration in the Northwest and the Tennessee Valley Authority in the Southeast) or other transmission entity.

For regulated utilities in **restructured states**, some of these cost elements will be missing. In most cases, the regulated utility will not own any generation assets. The regulated entity may serve certain functions with respect to power supply, such as the procurement of **default service** (also called standard service offer) for customers who do not choose a non-utility retail electricity supplier. However, these costs should be kept out of the cost of service study and cost allocation process and recovered within default power supply charges or as fees to retail electricity providers. In some restructured states, the regulated utilities still own certain types of transmission as a part of the regulated entity, which is subject to the traditional cost allocation process. In other states, transmission assets have been completely spun off into other entities. In many cases, the regulated utility is allowed to include these transmission costs as an allowed operating expense in determining the revenue requirement.

Depending on the mix of assets the regulated utility owns and the assets and operations of the larger holding company, which could span multiple states and even multiple countries, more complex jurisdictional allocation work may be necessary. The principles for jurisdictional allocation of generation and transmission, as well as billing and customer service, general plant and A&G expenses, are similar to those used for class cost allocation but do not have to be the same. Distribution investment costs generally are assigned to the jurisdiction where the facilities are located. Jurisdictional allocation is typically done as a part of the revenue requirement process and does not flow into the cost allocation process.

3.2.3 Range of Typical Utility Structures

Between the different ownership models and the mix of assets owned, there are dozens of different utility structures across the country. However, certain models are more common in particular areas:

- Nearly all IOUs outside of the restructured states are vertically integrated, owning and operating generation, transmission and distribution systems and billing customers for all of these services. Some municipal and public power entities are also vertically integrated, as well as a handful of large cooperative utilities.
- Generation and transmission (G&T) utilities own and operate power plants and often transmission lines, selling their services to other utilities (especially **distribution utilities**) and sometimes a few large industrial customers. A large portion of cooperative utilities are served by G&T cooperatives, typically owned by the distribution co-ops.

Several states have municipal power joint action agencies that build, buy into or purchase from power plants and may own or co-own transmission facilities. Many IOUs provide these services to municipal and cooperative utilities but are predominantly vertically integrated utilities serving retail customers.

- Flow-through restructured utilities operate distribution systems but do not provide generation services, leaving customers to procure those from competitive providers. Since generation prices are either set by a retail supplier in an agreement with a specific customer or determined by class from the bids of the winning suppliers in utility procurements for default service, generation cost allocation is not normally a cost of service study issue for these utilities.
- Distribution utilities own and operate their distribution systems but purchase generation and transmission services from one or more G&T cooperatives, federal agencies, municipal power agencies, merchant generators or vertically integrated utilities or through an organized market operated by an ISO/RTO. Outside of restructured states, most distribution-only utilities are municipals or cooperatives. The cost allocation issues for these utilities are similar to those for vertically integrated utilities, with the complication that the loads driving the G&T costs may be different from the loads used in setting the charges to the distribution utility.
- Some transmission companies solely own and operate transmission systems, generally under the rules set by an RTO. Their charges may be incorporated into the retail rates of distribution and flow-through utilities. In many cases, these transmission companies are subsidiaries of larger holding companies that own other electricity assets.

4. Past, Present and Future of the U.S. Electric System

Chapter 3 described the basic elements of the electric system in the United States today, but these elements developed out of a 130-year history of twists and turns based on technology, fuels, regulations and even international relations. Understanding the basics of these developments and how and why today's system was formed is relevant to several important cost allocation issues discussed later in this manual. With respect to cost allocation, four primary results of these changes are worth noting:

- A shift from fuel and labor costs to capital costs.
- The transition of new generation to non-utility ownership.
- Significant levels of behind-the-meter **distributed energy resources** (DERs), including rooftop solar.
- Significant increases in the availability, quality and granularity of electric system data.

Figure 13. Pearl Street Station, first commercial power plant in the United States

Source: Wikipedia. *Pearl Street Station*

4.1 Early Developments

Electricity generation and delivery started in the late 19th century with three essentially parallel processes:

- Privately owned companies built power plants and delivery systems in cities and near natural generator locations, starting with small areas close to the plants.
- Industrial plants built their own generation and connected other customers to use excess capacity.
- Municipalities set up their own systems, sometimes starting with the purchase of a small private or industrial facility, to serve the population of the city or town.

Initially, these utilities operated without regulation and competed with other fuels, such as peat, coal and wood, which were locally supplied. Municipalities had internal processes to set prices, but private utilities were able to charge whatever prices they wished. In this initial period, some cities did impose "franchise" terms on them, charging fees and establishing rules allowing them to run their wires and pipes over and under city streets. Multiple utilities emerged in some cities and competed against one another, which led to the building of duplicative networks of wires in many areas. These duplicative networks were aesthetically displeasing and considered by many to be economically wasteful. Relatively quickly, however, the natural monopoly characteristics led to the bankruptcy of many utilities or acquisition by a single dominant firm in each city.

In New York City, the winning utility, founded by Thomas Edison, eventually became the aptly named Consolidated Edison, or ConEd. Figure 13 depicts Edison's first generating station. New York established the first state economic regulation of electric utilities in 1900, and it spread widely from there. In New Orleans, the city remains the regulator of the IOU; its regulatory activity predated the creation of the state commission that regulates all IOUs operating outside of New Orleans.

4.2 Rural Electrification and the Federal Power Act

In the early period, regulatory authority over electric utilities was primarily exercised by states. In 1935, Congress passed the Federal Power Act, which vastly expanded the jurisdiction of the Federal Power Commission (now FERC) to cover interstate electricity transmission and wholesale sales of electricity. However, most economic regulation remained under the jurisdiction of state utility commissions, including authority over retail prices.

By the 1930s, most urban and suburban areas had access to electric service, but most rural areas did not. The Rural Electrification Act passed Congress in 1936, creating the Rural Electrification Administration to finance and assist the extension of service to rural areas through electric cooperatives, the Tennessee Valley Authority, various forms of public power districts and some state-sponsored utilities. The initial financing included significant federal support in the form of grants, technical assistance and very low-interest loans. A handful of states, including New York, North Carolina and Oklahoma, set up their own state power authorities to develop hydro facilities[16] and provide low-cost energy for economic development and other local priorities.

4.3 Vertically Integrated Utilities Dominate

By 1950, 90% of rural America was electrified, and access to electric service became nearly universal across the United States. Nearly all electric service was provided by vertically integrated utilities — which owned or contracted for power plants, transmission and distribution within the same corporate entity — or by municipal entities or cooperatives. The boundaries of service between different utilities became roughly stable in this time period and reveal the unique trends in each utility's development.

Many investor-owned utilities, especially in the Midwest and West, developed service territories that look like octopuses, with major urban areas and industrial loads connected by tentacles following the paths of transmission lines.[17] These utilities made business decisions to extend service to particular geographic areas where they believed the potential sales revenues would justify the cost of investment in transmission or distribution and still cover the additional costs of generation and customer service necessary to serve the load.[18] In each case, the utility expected that the sale of electricity would generate enough revenue to justify this expenditure.

Figure 14 on the next page shows the service territories of the Texas investor-owned utilities, illustrating these patterns (Association of Electric Companies of Texas Inc., 2019). Similar patterns are evident in the service territory maps of Minnesota, Delaware, Ohio, Oregon, Washington and Virginia. IOUs and municipal utilities generally serve densely populated areas, while cooperatives and public power districts, typically created and incentivized under the Rural Electrification Act, serve less dense areas.

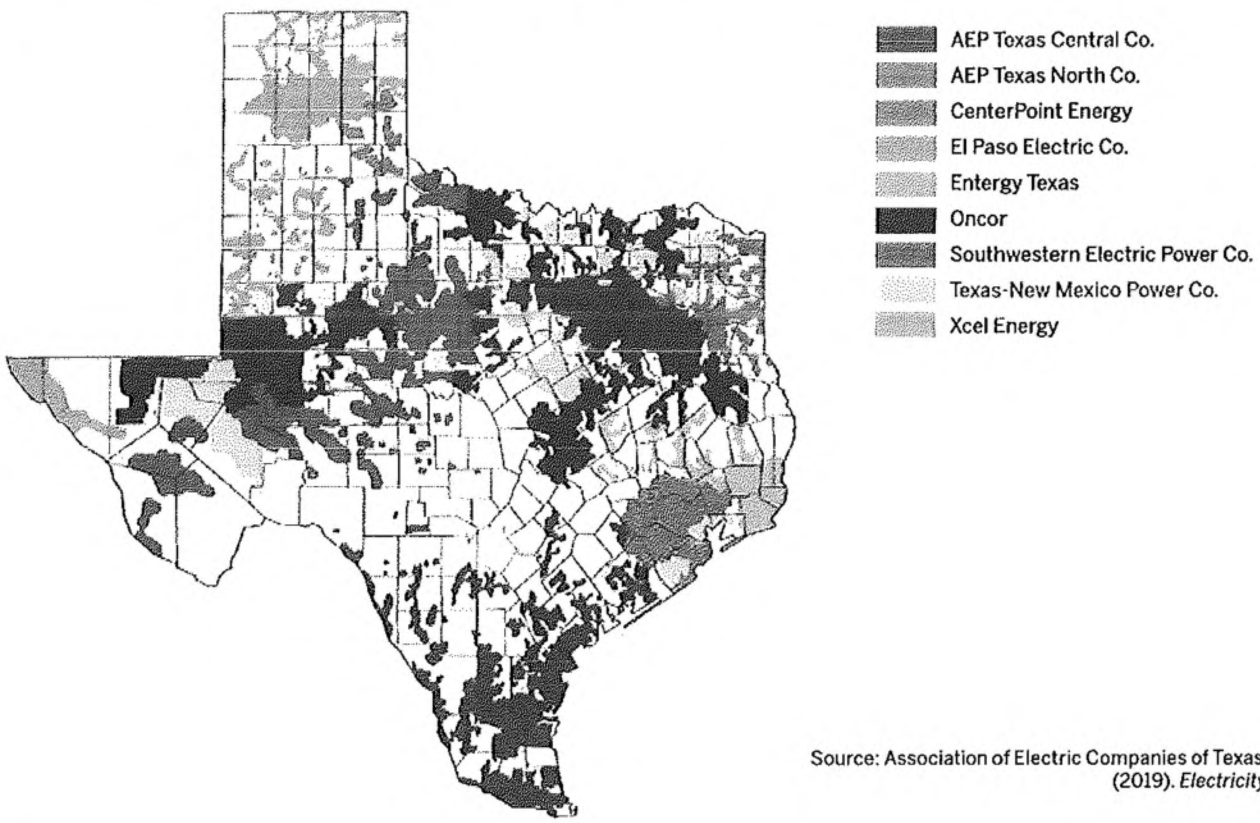
In some states, IOUs do serve some sparsely populated areas. This is often the result of a franchise grant by a municipality or a state mandate for service throughout an identified area to avoid islands where service is unavailable. The cost of this rural service is, to the utility, a price it must pay for access to the more densely populated area for a viable business, although ratepayers typically bear the higher costs of service.

16 Some of these state entities eventually assumed ownership of other types of generation.

17 In some states, such as Massachusetts, most of Maryland, Rhode Island and New Jersey, the IOUs serve large contiguous areas, regardless of density, due to historical and legal conditions in each state. In essence, the utilities incurred an obligation to serve less-developed areas as a price of obtaining authority to serve more densely populated areas.

18 In some cases, the IOU picked up dispersed service territory during the process of acquiring the assets of other power producers or to obtain state or local licenses for generation or transmission facilities.

Figure 14. Investor-owned electric utility service territories in Texas



Source: Association of Electric Companies of Texas Inc. (2019). *Electricity 101*

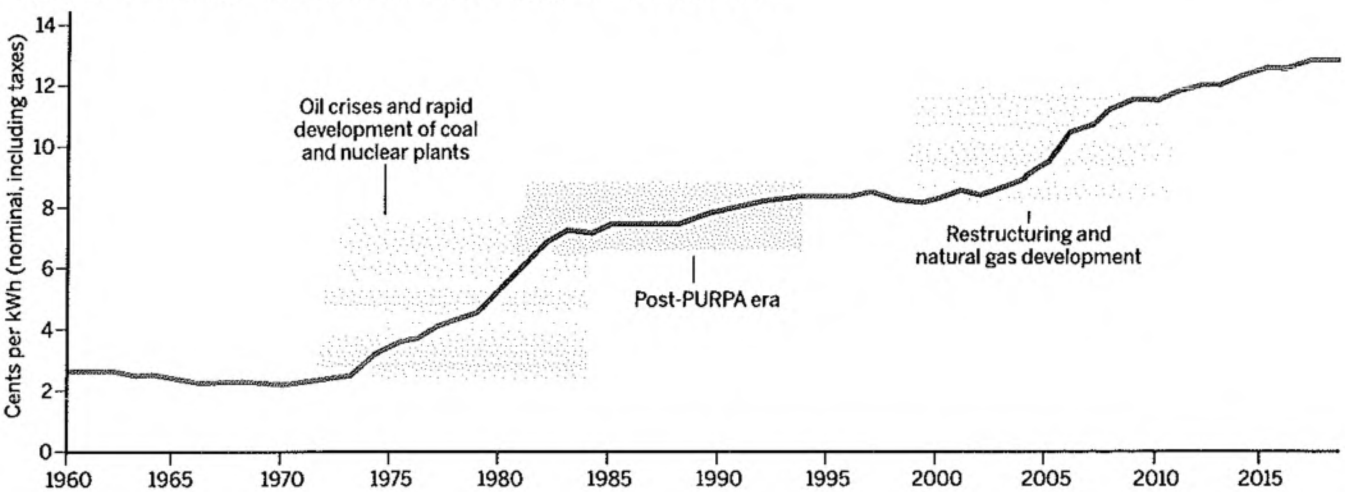
A cost analyst may need to examine these costs carefully to avoid shifting them to specific customer classes and to spread these costs systemwide.

4.4 From the Oil Crisis to Restructuring

From the 1950s to the early 1970s, electric sales skyrocketed due to a wide range of new electric end uses, and prices were relatively stable. However, the cost structure of the utility industry changed drastically after the 1974 oil crisis. Demand fell rapidly, particularly in locations where oil was used to generate electricity, in response to large price increases and fuel shortages. Natural gas prices, which had been partly regulated, were gradually deregulated over the next decade, but natural gas was thought to be in short supply and available only for certain uses. No new baseload power plants running more than 1,500 hours a year could be run on oil or natural gas under the Powerplant and Industrial Fuel Use Act of 1978, which was later repealed. In addition, generation of electricity with natural gas was to be prohibited at existing plants by 1990, with an exception for certain combined heat and power (CHP) facilities (Gordon, 1979). This law accelerated a trend toward the construction of large capital-intensive nuclear and coal power plants across the country in order to get away from the use of oil and natural gas for electricity. The confluence of all these trends, including high oil prices and expensive capital-intensive plants entering the rate base, led to major increases in electricity prices, as depicted in Figure 15 on the next page using U.S. Energy Information Administration data (2019).

Congress also passed PURPA in 1978, which included provisions intended to open up competition in the provision of electricity and to reform state rate-making practices. On the competition side, PURPA required electric utilities to purchase power from independent producers at long-term prices based on **avoided costs**. With regard to state rate-making practices, PURPA also required state commissions

Figure 15. US average retail residential electricity prices through 2018



Data source: U.S. Energy Information Administration. (2019, March). *Monthly Energy Review*

to consider a series of rate-making standards, including cost of service. This standard was widely adopted, but neither PURPA nor the state commissions defined "cost of service."[19] PURPA also requires some method to assure consumer representation in the consideration of rate design, through either a state consumer advocate or intervenor funding.

The widespread end result was low-cost energy generation (particularly after the fall in oil and gas prices in 1985-1986) and excess capacity in the 1980s, meaning the wholesale price of power was often much lower than full retail rates, even the supply portion of those rates. As a result, large industrial power users and municipalities began demanding the right to become wholesale purchasers of electricity. Given the changes in fuel markets, Congress repealed the limits on natural gas usage for electricity in the Natural Gas Utilization Act of 1987.

During the 1980s, major changes occurred in the telecommunications and natural gas industries, often termed deregulation but more accurately described as restructuring. Following these trends and the demands of larger purchasers for lower rates, Congress passed the Energy Policy Act of 1992.[20] This law called for open access to transmission service and paved the way for restructuring of the electric industry, including organized wholesale markets. In several parts of the country, including Texas and the Northeast, Midwest and West Coast, many states followed these trends and passed restructuring acts in the late 1990s, which required formal separation of certain asset classes and, in some cases, total divestment of generation assets. In several parts of the country, following voluntary criteria articulated by FERC in 1996, independent system operators were created to formalize independent control of the electric system and to administer organized wholesale markets for energy supply. FERC also articulated voluntary criteria in 1999 to form regional transmission organizations, which contain many of the same elements as the earlier ISO requirements (Lazar, 2016, pp. 21-23). There are currently six ISOs/RTOs operating solely in the U.S., two operating exclusively in Canada and one that includes areas in both countries:

- California Independent System Operator (CAISO).
- Electric Reliability Council of Texas (ERCOT).
- Midcontinent Independent System Operator (MISO),

19 The relevant provision of PURPA merely states: "Rates charged by any electric utility for providing electric service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the costs of providing electric service to such class" (16 U.S.C. § 2621[d][1]). This was clarified by the 2005 amendments to include "permit identification of differences in cost-incurrence, for each such class of electric consumers, attributable to daily and seasonal time of use of service" (16 U.S.C. § 2625[b][1]).

20 Pub. L. 102-486. Retrieved from https://www.govinfo.gov/content/pkg/STATUTE-106/pdf/STATUTE-106-Pg2776.pdf

spanning from North Dakota through Michigan and Indiana and down to Louisiana while also including the Canadian province of Manitoba.

- ISO New England (ISO-NE).
- New York Independent System Operator (NYISO).
- PJM Interconnection, spanning from New Jersey down through part of North Carolina and extending west through West Virginia and Ohio, while also including the Chicago area.
- Southwest Power Pool (SPP), spanning from North Dakota down through Arkansas, Oklahoma and northern Texas.
- Alberta Electric System Operator (AESO).
- Independent Electricity System Operator (IESO) in Ontario.

Organized wholesale markets for energy supply provide for structured competition among owners of power plants while meeting reliability and other constraints. These markets provide a nominal framework for competition but are in actuality much more deliberately constructed than any actual competitive markets that do not have the same reliability obligations. Cost analysts should pay careful attention to whether wholesale market structures and tariffs truly reflect cost causation.

In some states, retail customers were also given the option of choosing a new retail electricity supplier for the energy component of their rates, typically with utility-procured "basic" or default energy service as the more widely used option.[21] FERC regulates ISOs and RTOs, as well as the organized wholesale markets they run. However, each traditional regulated utility retained ownership of the distribution system as a natural monopoly regulated by the state, and states are the primary regulatory entity for retail electricity suppliers.

Several more states were either in the beginning stages of restructuring or contemplating restructuring in the early 2000s when a backlash from events in restructured states halted this trend. Chief among these events was the California energy crisis, where a drought-induced supply shortfall enabled energy traders to manipulate newly formed energy markets. In combination with infrastructure limitations and other features of the new California rules, this led to high wholesale market prices, the bankruptcy of one of the nation's largest utilities and even the recall and removal of California's governor.

4.5 Opening of the 21st Century

The beginning of the 21st century has seen another wave of dramatic change in the electric sector. Restructured areas have seen significant changes in investment patterns. New natural gas combined cycle plants have become a much more important source of generation. Aided by a drop in natural gas prices due to innovations in drilling technology, they have been able to outcompete other types of generation. This has meant significant retirements of other types of generation, starting with older oil and coal units, which have also been affected by new pollution control requirements over the last several decades. More recently, nuclear plants built in the 1960s through 1980s have started to be retired, or their owners have claimed that low energy market prices require additional financial support to enable their continued operation.

In addition, global market developments and federal, state and local policies for renewable generation, as well as energy efficiency and demand response, have led to significant expansions in new resources that have zero pollution and low marginal costs. Many states have adopted **renewable portfolio standards** (RPS) to accelerate the adoption of new renewable technologies, sometimes with requirements for solar or other specific technologies. Storage technology innovation has further increased options for grid flexibility and reliability. New technologies to monitor and manage the electricity grid have also become much more prevalent as a result of continued innovation, cost decreases and policy support.

Some jurisdictions are looking at how to maximize the benefits of customer-sited investments in energy efficiency, energy management and distributed generation. Notable examples are the Reforming the Energy Vision process in

21 Texas is the exception, without any option for utility-provided energy supply service.

New York, E21 in Minnesota and the distribution resources plan proceedings in California. These efforts may even extend to new market structures at the retail level and new platforms for customers and third parties to exchange data and to offer and receive new types of services.

Changes in the electricity system affect many parts of the cost allocation process.

First, a utility cost study performed in 1980 might have placed 70% of the utility revenue requirement in the categories of fuel and purchased power, which are generally considered short-run variable energy-related costs. Since that time, capital has been substituted for fuel, in the form of wind, solar, nuclear and even high-efficiency combined cycle units running on low-cost natural gas. Many variable labor costs for customer service and distribution employees, including meter readers, have been displaced with capital investments in distribution automation and smart grid technologies. As energy storage evolves, even peak hour needs may be met with no variable fuel costs incurred in the hour when service is actually provided. Instead, power may be generated in one period with a variable renewable resource with no fuel cost[22] and saved for a peak hour in a storage system with almost no variable operating costs.

Second, a significant share of electricity generation is now owned by non-utility investors. Some of this shift is driven by federal tax code provisions, some is due to the emergence of specialized companies that build and operate specific types of power generating facilities, and some is due to public policy decisions to limit ownership of generating resources by traditionally regulated utilities. As a result, costs attributable to these sources of generation are primarily the cost of the energy — which is not divided up into capital costs, maintenance costs, etc., as it was when the generation plant was owned and operated by the utility. The 2005 amendments to PURPA, which state that time-differentiated cost studies must be considered, provide an imperative to think carefully about how to assign costs to time periods.

Third, a range of supportive state and federal policies, combined with falling costs, have led to major increases in DERs, notably rooftop solar. Advanced energy storage may be the next great wave on this front, enabling both widespread energy management and backup power resources.

Fourth, today's sophisticated data and analytical capabilities present regulators and analysts alike with a wide range of new choices. Several decades ago, analysts were limited to simple categorizations and shortcuts. This includes the traditional division of costs as customer-related, demand-related or energy-related. Regulators are no longer bound by these limitations and should seek to improve on dated techniques.

22 For example, Xcel Energy has put forward a "steel for fuel" program, which substitutes wind and solar facilities for fuel-burning power plants (Xcel Energy, 2018, p. 5).

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Part II:

Overarching Issues and Frameworks for Cost Allocation

5. Key Common Analytical Elements

Several key analytical processes and decisions must be made regardless of the overall framework and specific methods used for cost allocation. These common analytical elements include:

- Cost drivers: What are the key factors that lead different types of costs to be incurred?
- Determining customer classes: How many classes of customers should be categorized separately, and how is each class defined?
- Load research and data collection: What are the key patterns of load, delivery and generation that need to be recorded and analyzed? For any key data that are not tracked comprehensively, is sampling or another approach used?

In any individual rate case, these issues may not be litigated at great length, and many or all parties may rely on past practices and precedent. But the decisions made on these issues historically by each public utility commission can have important consequences in the present, particularly as changes to technology and the regulatory system undermine the basis of past assumptions.

5.1 Cost Drivers

Effective cost allocation and rate design require the identification of central cost causation factors, or cost drivers. Within these processes, it is important to identify relatively simple metrics (e.g., energy use in various periods, demand at various times, numbers of customers of various types) that can be associated with the various customer classes. The cost allocation process, by its nature, approximates cost responsibility and is not a tool of exceedingly precise measurements.

One crucial underlying reality is that customers use electricity at different times, leading to the concept of **load diversity**. Load diversity means the shared portions of the system need to be sized to meet only the **coincident peak** (CP) loads for combined customer usage at each point of the system,[23] rather than the sum of the **customers' noncoincident peak (NCP) loads.**[24] This diversity exists on every point of the system:

- Customers sharing a transformer have diverse loads.
- Loads along a distribution feeder circuit have diversity.
- Multiple circuits on a substation have diversity.
- The substations served by a transmission line have load diversity.
- Individual utilities in an ISO territory or regional transmission interconnection have diversity.

Diversity of load means the actual electricity system is significantly less expensive than a system that would be built to serve the sum of every customer's individual NCP. Holding **peak load** for a customer constant, this also means that a customer with load that varies over time is effectively much cheaper to serve than a customer that uses the same peak amount at every hour. The former customer can share capacity with other customers who use power at other times, but the latter cannot.

Another important reality is that the accounting category to which a cost is assigned does not determine its causation. An expense item may be due to energy use, peak demands or number of customers; the same is true for capital investments. Capital costs and other expenses that do not vary with short-run dispatch changes are referred to as fixed costs by some analysts, and some cost of service studies assume that

23 As explained throughout this section, the critical coincident peak load may be a single peak hour but more typically is some combination of loads over multiple hours.

24 Several other terms are used for individual customers' noncoincident peak demand, including "undiversified maximum customer demand." Unfortunately, both "NCP" and "maximum customer demand" can also be used to refer to various class peaks, particularly when used with modifiers. This manual will use "customer NCP" to refer to individual customer peaks and "class NCP" to refer to aggregated peaks by class, often specifying the level of the system for the relevant class NCP. Class NCP is sometimes referred to as the maximum class peak, maximum diversified demand or other similar terms.

these notionally fixed costs cannot be driven by energy use. As discussed in the text box on pages 78-79, this assumption is incorrect. Utilities make investments and commit to "fixed" expenses for many reasons: to meet peak demands, to reduce fuel costs, to reduce energy losses, to access lower-cost energy resources and to expand the system to attract additional business. As a result, this manual will use the phrase "dispatch O&M costs" to reflect operations and maintenance costs that vary directly with generation output and "nondispatch O&M costs" for O&M costs that are incurred independently of output levels.

5.1.1 Generation

There are several different categories of generation costs, with different lengths of time for the commitment. Depending on the technologies in question, long-term capital costs, nondispatch O&M costs and per-kWh fuel costs are substitutable — that is, a wind generator with a battery storage system involves more capital cost and lower operating cost than a natural gas combustion turbine unit with the same output.

The longest-lived category of generation costs is capital investment in generation facilities, which are often depreciated on a 30-year timeline and can last even longer. Once the investment is made, the depreciation expense typically will not vary over that time. Of course, a generation facility can be permanently shut down (retired), temporarily shut down (mothballed) or repurposed before the depreciation period is over. Different costs and benefits may be incurred for each of these three options. It is also possible for a plant's life to be recalculated at some point, with an appropriate change in the depreciation schedule and the annual depreciation expense.

There can be significant capital investments and nondispatch O&M costs that are incurred on an annual or monthly basis, which may not vary directly with the numbers of hours the facility operates. There are also capital investments that are driven by wear and tear, rather than the passage of time.[25]

The shortest-term variable costs for utilities are mostly fuel costs and the portions of power purchases that vary with energy taken. In addition, some O&M costs are usually considered variable with output: the costs of some consumable materials (especially for pollution control equipment), as well as the costs of replacements (such as lubricants and filters) and overhauls that are required after a specified amount of output, equivalent full-load hours of operation or similar measures.[26]

In many cases, utilities classify costs based on accounting data and administrative convenience, rather than the underlying reasons why the costs were incurred and why any capital investments are still part of the system. For example, utilities may treat some O&M and interim capital additions as variable and energy-related for one set of purposes, such as rate design or evaluation of potential generation resources, but treat the same costs as demand-related for cost allocation purposes for simplicity. Cost of service studies are normally driven primarily by accounting data that do not readily differentiate dispatch O&M costs from nondispatch O&M costs and capital additions.

Similarly, other costs, such as pollution controls and ash handling and disposal at coal plants, include significant long-run investments that were specifically incurred to support the energy generation process and generally should be treated as energy-related. These investments would not be needed or would be less costly either if the plant were run less often or if the fuel were less polluting.

Short-Run Variable Generation Costs

The short-run variable cost of power generation is typically straightforward, primarily entailing a mix of fuel costs, dispatch O&M costs for utility-owned generation and purchased power. As a result, the drivers of these costs are typically fuel prices, market prices for energy and any ongoing contracts the utility has. Utilities can hedge the risk of short-term energy generation costs through a wide range of means, including futures contracts for fuel and power.

The short-run variable costs of some generation facilities, including storage and dispatchable hydro, are very low. Storage facilities require the operation of other resources (which may well have variable costs) to charge them. Dispatch

25 These costs are comparable to tire replacements that are caused by wear and tear closely correlated with miles driven.

26 These costs are comparable to the costs of automotive oil changes and routine services that are the consequence primarily of miles driven.