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MODULE III: GUIDELINES ON DETERMINING THE PROCESS FOR ALLOCATING COSTS AMONG CUSTOMER CLASSES

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MODULE III: GUIDELINES ON DETERMINING THE PROCESS FOR ALLOCATING COSTS AMONG CUSTOMER CLASSES

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List of Acronyms and Abbreviations

ABC	Activity-based costing
A&G	Administrative and general
AMI	Advanced metering infrastructure
Capex	Capital expenditure
COSS	Cost-of-service study
CP	Coincident peak
DERs	Distributed energy resources
FERC	Federal Energy Regulatory Commission
ISOs	Independent System Operators
kV	Kilovolts
kW	Kilowatt
kWh	Kilowatt-hour
MWs	Megawatts
NARUC	National Association of Regulatory Utility Commissioners
NCP	Noncoincident peak
Opex	Operating expenditure
O&M	Operations and maintenance
PPA	Power purchase agreement
RAP	Regulatory Assistance Project
RTOs	Regional transmission organizations
T&D	Transmission and distribution
USOA	Uniform System of Accounts
USA, US	The United States of America

1 Module III: Guidelines on Determining the Process for Allocating Costs Among Customer Classes

1.1 Cost Allocation

This section is an overview of cost allocation and its principles, main allocation methods, and cost categories in the electric system. In addition, this section provides a general overview of key cost allocation frameworks: marginal, embedded, and incremental cost allocation studies.

1.1.1 Principles and Key Terms of Cost Management and Allocation

Basic cost management and allocation methodologies in cost-of-service study (COSS) frameworks should follow these principles to fairly distribute the revenue requirement among the rate classes:

- Cost-causative: there is a connection between what led to the spending and how it affected the business unit that benefited from the activity
- Measurable: amounts are documented in the financial records and are auditable, subject to internal controls
- Objective: the approach decides how costs should be distributed without prejudice
- Predictable and stable: the process does not result in variations that do not correspond to changes in service level
- Consistently applied: for each user of the service, the computed cost per unit should be the same

Before considering the key frameworks within the COSS in detail, it is important to illustrate the traditional (standard) allocation method and activity-based costing (ABC) methods.

1.1.2 Traditional (Standard) Allocation Method

In the traditional allocation method, standard costs are allocated to produced units in a standard cost system. The average cost of creating one unit of output is calculated by multiplying the standard cost of one unit of each of the inputs by the number of units of that input that can be used to produce one unit of output. Direct materials, direct labor, and allocated overhead are included in the inputs. The cost that should apply to that unit of output is known as the standard cost.

The standard price or rate per unit of direct materials or direct labor is multiplied by the standard quantity of direct materials or direct labor permitted for the actual output. This is how direct materials and direct labor are applied to production. The metric that most accurately depicts what generates overhead costs should be used as the allocation base. Direct labor hours, direct labor expenses, or machine hours are the most popular allocation bases. Direct labor hours or direct labor expenses are generally the best allocation bases for manufacturing processes that require a lot of labor. The superior allocation base for a production process focused on equipment is the number of machine hours.

The standard overhead cost to be applied to the units produced is determined by multiplying the predetermined overhead rate by the standard amount of the allocation base permitted for producing one unit of the product. This standard overhead amount for one unit is then multiplied by the actual number of units produced. Allocating the numerous indirect production expenses based on a single element is likely to produce inaccurate costs for a manufacturer's products. The ABC method identifies all activities that take place and only allocates the expenses of those activities to the goods/services.[1]

[1] Averkamp H., "What is the traditional method used in cost accounting?" Accounting Coach. 2020. https://www.accountingcoach.com/blog/taditional-method-cost-accounting

1.1.3 ABC Method

The standard approach to allocating costs to items was created to value total inventories. However, as was indicated before, it does not always give a clear image of the cost information for the goods. When using traditional costing, fixed manufacturing expenses are uniformly distributed to each product, even though the resources may be used by different products in different ways. Additionally, fixed manufacturing overhead costs are typically misallocated to products under traditional costing methods because they are treated as variable costs, which distorts information about product costs. Products may be "under-costed" in some cases or "over-costed" in others.

Another approach to distributing overhead costs to goods is ABC, which bases its method of allocation on cost drivers. ABC is a mathematical process, just like the other ways for allocating overhead. It includes identifying the costs to be distributed, then distributing them in some way to various cost objects, such as processes, products, or other cost objects. Both manufacturing and nonmanufacturing overheads can be calculated using ABC in a variety of circumstances. It is also applicable to service-based industries.

ABC is described as "a methodology that measures the cost and performance of activities, resources, and cost objects based on their use" by the Institute of Management Accountants. ABC is aware of the causal links between cost drivers and activities. An ABC system requires more effort, time, and money to set up than a conventional system does. It entails actions like 1) activity identification; 2) finding the cost-related drivers; and 3) determining cost pools.

An activity is a task, event, or unit of labor that has a specific objective. Designing things, assembling machinery, running machines, placing orders, or distributing products are a few examples of activities. Anything for which costs are accrued for managerial objectives is a cost object. A particular job, a product line, a market, or a particular consumer are examples of cost objects. A cost driver is anything that generates expenses each time it occurs. This could be an action, an event, or the volume of a substance. Cost drivers may be executional or structural.

Calculating the full production cost per unit using ABC requires five basic steps: 1) grouping production overheads into activities, according to how they are driven; 2) identifying cost drivers for each activity, (i.e., what causes these activity costs to be incurred); 3) calculating an overhead absorption rate for each activity; 4) absorbing activity costs into the product; and 5) calculating the full production cost and/or the profit or loss.[2]

1.1.4 Categories of Costs in the Electric System

Costs associated with the electric utility system are often broken down into several categories, including those associated with generation, transmission, distribution, billing, customer service, and administrative and general (A&G). This section focuses on five categories of the cost in the electric system.

1.1.4.1 Generation

The first category of cost in electric system is electricity generation. Numerous technological innovations that make use of a wide range of fuels and resources are responsible for the creation of electricity. The cost structure of each of the electric systems might vary depending on the fuel used. This is typically broken down into three categories: 1) initial investment costs, also known as capital costs; 2) operations and maintenance (O&M) costs, which may vary depending on how many hours a facility generates; and 3) fuel costs, which can occur regularly on a monthly or annual basis.

[2] "Chapter 1: Traditional and advanced costing methods." Kaplan Financial Knowledge Bank. https://kfknowledgebank.kaplan.co.uk/acca/chapter-1-traditional-and-advanced-costing-methods

Fuel costs are the major component of the expenditure associated with the process of generation electricity. Each fuel has a different cost associated with the delivery, handling, and disposal of any byproducts before use. For instance, it is necessary to dispose of both nuclear waste and coal ash, yet there are various issues and costs involved with each. Renewable energy sources that do not burn fuel have very high capital costs and very low variable costs. Storage resources often have high initial investment costs, low operational costs, and moderate maintenance expenses. Generation facilities are frequently categorized by their intended use and other characteristics. Among such categorizations, utilities could be classified as baseload units, peaks, or intermediate units.[3]

1.1.4.2 Transmission

Transmission systems are made up of high-voltage lines that are over 220 kilovolts (kV), often carried by big towers and substations that connect the transmission lines to one another as well as between generation resources and consumers. Transmission performs several overlapping tasks, such as connecting inherently far-flung generation to load centers, allowing power from a variety of generators to reach any distribution substation to enable least-cost economic dispatch to lower fuel costs, giving access to nearby utilities for reserve sharing, economic purchases and economic sales, allowing generation in one area to serve as a backup in another area, and minimizing energy losses between generation sources.

Transmission costs are made up of the costs associated with building new equipment as well as the continuing operating expenses (such as maintenance and losses) associated with these assets. Transmission function consists of assets and costs most often related to processes such as bulk transmission, the integration of remote generation, economy interconnections, local network, and transmission substations.

1.1.4.3 Distribution

For the vast majority of consumers that use distribution-level service, distribution substations and lines are necessary. Power is primarily transferred from the transmission system to the distribution system via distribution substations, which reduces greater transmission-level voltages to distribution-level voltages. Direct power delivery from tiny generators, such as decentralized generation and small hydro plants, may be used to power the distribution system in some cases. Transmission substations in miniature form are known as distribution substations. Sub transmission lines, which can operate as either transmission or distribution in cost studies, are frequently used to connect these. Transmission and distribution (T&D), or the delivery system, is the collective term for the T&D systems.

Customers who receive service at primary voltage are sometimes referred to as primary customers such as primary general service or primary commercial. Similarly, consumers served at secondary voltage can be classified as secondary customers. Costs usually associated with distribution are:[4]

- Engineering indirect costs: costs incurred during such activities as network policy, network design, project management, and engineering management and clerical support
- Network indirect costs: includes costs associated with activities of wayleave administration, control center, system mapping, call center, stores and procurement, vehicles and transport, and health and safety and operational training
- Business support costs: cost related to activities of information technology and telecommunication, property management, Human Resources and non-operational training, finance and regulation, CEO, etc.
- Costs associated with inspections, maintenance, and tree cutting

[3] "Electric Cost Allocation for a New Era: A Manual." Regulatory Assistance Project (RAP), 2020.
[4] McKenzie, Bill. "Electricity Distribution Cost Review 2006-2007." Ofgem. 2007. https://www.ofgem.gov.uk/sites/default/files/docs/2007/12/elec-dist-cost-review-200607-ref-28907_0.pdf

1.1.4.4 Metering, Billing, and Customer Service

Metering is typically viewed as a customer-specific expense for invoicing purposes. But there is a considerably larger range of uses for advanced metering technology, including system planning and energy management. This suggests that larger cost allocation strategies ought to be employed. Meter reading used to be a significant labor expense, requiring meter readers to visit each meter every billing cycle to assess usage. However, utilities using advanced metering infrastructure (AMI) technologies have either completely removed or drastically decreased the associated labor costs.

For a variety of related practical reasons, most utilities bill clients either monthly or bimonthly. If consumers were billed less regularly, some might get enormous amounts that would be difficult to manage without extensive planning. The costs associated with billing would be much higher if done more regularly. Customers can better understand their usage patterns from month to month when their bills are sent closer to the moment of consumption, which may help them be more productive and react to pricing signals.

In the past, billing information was quite straightforward, and the main expenses associated with sending out bills were printing and postage. Billing data has become significantly more complicated because of AMI, necessitating new system and cybersecurity needs. On the other hand, online billing can save some costs and make client data more accessible.

Due to a customer's financial issues, their removal from the service area, or any other reasons, bills may go unpaid. The costs of unpaid bills are referred to as uncollectible, and often considered as an adjustment when calculating the revenue required as a proportion of anticipated bills to maintain utilities. Deposits are necessary in some countries to safeguard utilities against unpaid bills. Customer service includes a wide range of offerings from resolving basic billing-related queries to handling intricate interconnection problems for distributed generation. The category of consumer can have a big impact on these costs.

While some governments permit utilities to charge for general marketing and advertising expenses, others demand that shareholders pay for any such expenses. As part of public policy initiatives, more specifically targeted advertising costs for energy conservation and safety are frequently recouped from ratepayers.

1.1.4.5 A&G Costs

Additionally, utilities incur a wide range of overhead expenses, referred to as A&G expenses. They include necessary capital expenditures, also referred to as general plant, and ongoing costs, usually referred to as general and administrative costs. The general plant consists of vehicles, computers, and office buildings. Executive salaries, pensions for retired personnel, and costs associated with regulatory processes are only a few of general and administrative costs. These expenses support all utility's functions, which is their underlying characteristic.

1.1.5 Key Frameworks on Electric Cost Allocation

Cost allocation studies are divided into two main categories: embedded and marginal cost studies. Embedded cost analyses examine the current expenses that go toward the current revenue demand. Studies of marginal costs examine price changes that will result from shifting customer demands over an acceptable planning horizon of maybe five to twenty years. Besides the embedded and marginal costs analyses, this section covers brief information on long run incremental costs. Regulators may want to consider more than one type of study when making allocation choices for major utilities that have an impact on millions of users because each is important in finding the best distribution of costs.

1.1.5.1 Marginal Costs

The ambiguity surrounding the idea of a cost being "fixed" is one of the issues with utilizing the fixed/variable dichotomy to classify costs. Almost all observers concur that some generation costs vary because they are short-term marginal costs that change in direct proportion to demand patterns. These prices consist of:

- The cost of buying and disposing of fuel
- Variable operating expenses for the consumables (such as water, limestone, activated carbon, and ammonia) injected to boost output, cut emissions, or cool the power plant as it generates electricity
- The need to buy permits or offsets to emit different pollutants
- Charges for purchased power that are based on the amount of energy used by the utility

The core tenet of marginal cost pricing is that, as opposed to historical embedded costs, economic efficiency is best achieved when prices reflect current or future costs, or, more specifically, the current genuine value of the resources being used to meet demand. Marginal cost approaches have detractors, who frequently point out that this economic theory is only applicable in certain circumstances (such as when all other items are priced according to marginal costs, there are no obstacles to entry or exit from the market).

1.1.5.2 Embedded Costs

Embedded COSS, often known as "fully allocated COSS," are the most popular type of utility cost allocation study. Nearly all self-regulated utilities rely on embedded COSS, and most state regulators mandate them. These studies stand out because they concentrate on the cost-of-service and consumption patterns in a test year, which is normally either the year before the rate case is filed or the year that starts after it, when new rates are supposed to go into effect. As a result, there is essentially a static snapshot method and very little that takes changes over time into consideration.

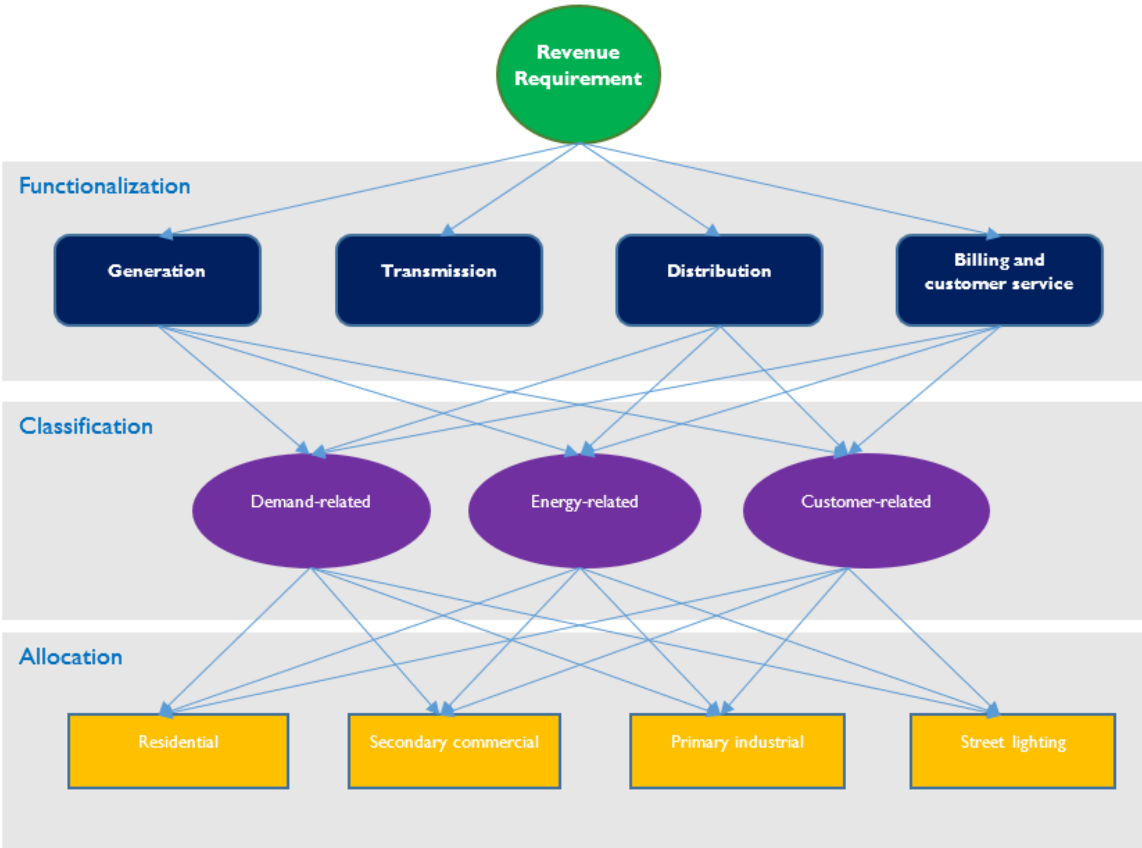
1.2 Marginal vs. Embedded Cost Studies

Cost allocation studies are divided into two main categories. Embedded cost analyses examine the current expenses that go toward the current revenue demand. Studies of marginal costs examine price changes that will result from shifting customer demands over an acceptable planning horizon of about five to twenty years. This section provides comparison analysis on embedded and marginal COSS and describes ways of combining these frameworks.

1.2.1 Embedded COSS

There are three main steps of embedded cost studies: functionalization, classification, and allocation. In the traditional model shown in Figure 1 below, functionalization identifies the function that each cost (or the underlying equipment or activity) serves, classification identifies the broad category of factors that drive the need for the cost, and allocation chooses the parameter to be used in allocating the cost among classes.

Figure 1: Traditional embedded COSS flowchart



Source: Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). "Electric cost allocation for a new era: A manual." Regulatory Assistance Project. 2020. https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf

1.2.1.1 Functionalization

In the first step, costs are assigned to the major functional groups involved in service provision. Functional assignment involves allocating costs to utility functional services such as power generation, purchasing electric power, the transmission of power over high-voltage lines, and distribution of power over distribution lines. Much research on the COSS sub functionalizes some costs within a function. For instance, within the generation function, the cost is differentiated based on type of electric generation: baseload generation, intermediate generation, and peaking generation.

1.2.1.2 Classification

In the second step, the major cost drivers for each functionally assigned cost group are classified. Identifying the major cost drivers allows the service characteristics that give rise to the costs to serve as a basis for allocation. Once the costs are functionalized, the major cost drivers usually classify them:

- Energy-related costs
- Demand-related costs
- Customer-related costs

1.2.1.3 Allocation

The functionally assigned and classified costs are then directly allocated to the customer classes based on an allocation factor (allocator) that is representative of the service characteristic that drives the utility's costs in the third and final step. For example, energy-related costs are allocated based on the number of kilowatt hours (kWh) used by the customer class, whereas demand-related costs are allocated based on the appropriate measurement of the maximum demand placed on the system by the customer class.

1.2.2 Marginal COSS

Marginal COSS cover how costs fluctuate over time and which rate class features are responsible for driving variations in cost, as opposed to the static snapshot that is typical of embedded cost approaches. It is crucial that marginal costs can be calculated in both the short- and long-term. The portion of the cost-of-service that varies from hour to hour with demand, assuming no changes in the capital stock, will only be measured in a true short-run marginal cost analysis. A comprehensive service long-run incremental cost study, on the other hand, estimates the cost of replacing the current power system with a brand-new, perfectly proportioned, and constructed system that makes use of the most recent technology.

1.2.2.1 Short-run Marginal Cost Pricing

When some production factors, generally capital facilities, are fixed the short run marginal costs (SRMC) calculate the future cost required to transmit one kW or kWh over networks. Network losses and network congestion costs are among the short-term marginal costs.[5] Although short-run marginal cost approaches can be considered less complex, they are only useful in a small number of situations and largely deal with changes in fuel usage and purchased electricity costs.

Common calculations for short-run marginal energy costs are done on a time-differentiated basis using a production cost model or a comparable model. These computations are performed over one to six years out, depending on the utility. Some utilities experience significantly higher marginal costs or market prices during extreme winter weather. This happens because in winter periods there are such factors as gas price spikes, gas availability restrictions, high peak loads that lead to the unreliability of service due to the freezing of coal piles, some mechanical parts of power plants, and gas wells.

1.2.2.2 Long-run Marginal Cost Pricing

The steady costs that a business may forecast and plan for overall are known as long-run incremental costs. The term is used to describe the shifting costs that a business may reasonably predict. Increasing energy and oil prices, rising rent, expanding costs, and maintenance costs are a few examples of long-term incremental costs. Customers are often charged for electricity at a price that considers the expenses of network construction and generation.

The cost of supplying an extra unit on the assumption that all production parameters can be varied is known as long-run marginal cost (LRMC). LRMC pricing calculates the future cost required to transport one kW or kWh over networks. When energy demand has increased, LRMC has often been driven by network investment. For example, increased network investment to sustain the quick uptake of air conditioners. Different methods can be used to compute and apply LRMC. Distributors have the freedom to implement LRMC in a way that best fits their network and customer demographics. However, there are a number of elements that distributors must consider while determining and applying LRMC, such as:[6]

- The costs and benefits of calculating, putting into practice, and using the proposed method

[5] Lazar, J., Chernick, P., Marcus, W., and LeBel, M. "Electric cost allocation for a new era: A manual." Regulatory Assistance Project (RAP). 2020.

[6] "Network tariffs and long run marginal cost." Australian Energy Regulator. 2021. https://www.aer.gov.au/system/files/AER%20-%20Explanatory%20note%20-%20Network%20tariffs%20and%20long%20run%20marginal%20cost_0.pdf

- The extra costs likely to be incurred in order to meet demand from retail customers assigned to that tariff during periods when the relevant part of the distribution network is being used to its fullest capacity
- The location of retail customers assigned to that tariff, and the degree to which costs vary between different locations in the distribution network

There are two widely used approaches to calculate LRMC: 1) the average incremental cost (AIC) method, and 2) the Turvey perturbation method, also known as the Long Run Incremental Cost (LRIC) approach.[7] The AIC approach determines the price point at which future output increases must be set in order to guarantee an entire incremental cost recovery in light of projected demand. The AIC approach is thought to be less expensive to implement than some other methods, but it results in less precise estimations.

LRIC charging mechanisms have the potential to reduce network investment costs.[8] This method is acknowledged as an economically effective method for allocating network costs, since it calculates network charges based on the variation in the present value of future investments because of nodal power disturbance due to changes in demand or generation. Improved versions of the LRIC approach consider nodal unreliability tolerance, component reliability, and network security.

Both methods have several advantages and disadvantages that could be seen in the table below:

Table 1: Advantages and Disadvantages of AIC and LRIC

Method	Advantages	Disadvantages
AIC	Significantly reduces SRMC-related variability but does not entirely eliminate it. When costs in the long-term are highly uncertain and/or greater emphasis is placed on short-run costs, putting additional weight on costs incurred in near future would be considered as an advantage. [9]	There are problems with LRMC. The LRMC pricing has problems, such as sending an ineffective price signal for decisions made in the short-term and results that depend on the duration of the chosen period;[10] and puts more weight on costs that will be incurred in the future periods. As a gauge of LRMC, this might be viewed as being less accurate.
LRIC	This model considers user security choices while estimating how they would affect the price of network construction; calculates the cost of a marginal permanent demand shift more precisely; when there are significant capital investments, unpredictability may be even more minimized; and it is useful for isolating the LRMC of a single cost driver.	This highlights problems with LRMC pricing (e.g., inefficient signals in short-term); the diversity factor is used to determine the maximum demand at various network nodes when determining nodal LRIC charges. This component considers each user's maximal demand, which could not match with the peak demand on the network. Therefore, this element is unable

[7] Tooth, Richard. "Measuring long run marginal cost for pricing." Sapere Research Group. 2014. https://srgexpert.com/wp-content/uploads/2017/11/Tooth-LRMC-for-Pricing-vFinal.pdf
[8] Mujeeb, Asad & Peng, Wang. "Long Run Incremental Cost (LRIC) Distribution Network Pricing in UK: advising China's Distribution Network." 2022.
[9] Tooth, Richard. "Measuring long run marginal cost for pricing."
[10] Ibid.

Method	Advantages	Disadvantages
		to accurately reflect user network utilization during periods of high demand. As a result, the method does not assess fees to users based on how much they contribute to network peak times.

1.2.3 Advantages and Challenges of Embedded COSS

The advantages and disadvantages of embedded COSS include:

Advantages	Disadvantages
• Simplicity – costs are easily identified • Attribute costs to different categories of customers based on how those customers cause costs to be incurred. For instance, energy sales and contribution to peak methodologies allocate costs to those customers who most contribute to each • Separates costs between different regulatory jurisdictions • Determine how costs will be recovered from customers within each class	• Some of the allocations are arbitrary • Off-system and non-firm sales are removed prior to the allocation step • There is considerable disagreement over the number of coincident peaks (CPs) that should be used for allocating demand costs • Incorrectly generates efficient signals (breaking the principle of cost causation)[11]

1.2.4 Advantages and Challenges of Marginal COSS

The advantages and disadvantages of marginal COSS include:

Advantages	Disadvantages
• Represents the main principles of economics and generates appropriate efficiency signals • Because it avoids the complexity of apportioning fixed costs, which is truly arbitrary, it is simple to grasp and simple to utilize • There are no issues with excessive or insufficient overhead absorption • It prevents the carryover of a portion of the fixed overhead from the current period to the following period • It establishes a clear connection between break-even analysis and cost, sales, and output volume	• Mixed time horizons. Marginal cost methods often mix short-run, intermediate-term and long-run marginal costs in an inconsistent manner that has tended to have inequitable results over the last 30 years[12] • Prices need to be modified in real-time to maximize efficiency because marginal cost is uncertain • Additional measures to guarantee fulfilling revenue requirements can be required (e.g., Ramsey pricing) • Outdated method due to evolving resource sources. Economic dispatch has essentially been used to create marginal energy and

[11] Parmesano H., Nieto A., Irastorza V. "Survey of Electric Utility Embedded Cost Methods for Generation and Transmission in North America." Paschim Gujarat Vij Company Limited. 2003. https://www.pgvcl.com/Whatsnew/PGVCL%20-%20CoS%20Report-FY2018_19.pdf
[12] Lazar, J., Chernick, P., Marcus, W., and LeBel, M. "Electric cost allocation for a new era: A manual."

	generation capacity cost allocation methods for fossil-fueled systems, whether they are short-run or long-run • Handling of renewable energy. Short-run marginal energy costs are much lower than the cost of new generation because of the substitution of renewables for fossil fuels (which have relatively high capital costs but essentially no variable costs), with important consequences for cost allocation • It is quite difficult technically to separate costs into fixed and variable components

1.2.5 Combining Embedded and Marginal Frameworks

To support cost allocation and rate design, many jurisdictions need both an embedded and a marginal COSS. As a result, during a rate proceeding, utilities and other parties may produce multiple studies. To determine a range of reasonableness, a regulator may justifiably use several cost analyses to inform their conclusions. The regulator can use discretion and all pertinent non-cost considerations to determine how the required revenues should be distributed among the classes within that range. Additionally, several study kinds offer various data that can be applied at various phases of the rate-making process.

In some cases, regulators will establish rates using one costing approach for the load that already exists while using a separate way to set prices for new consumers or incremental usage. This method has been used in several jurisdictions for rate design within classes, serving as the basis for most "economic development" rate discounts when embedded costs are lower than marginal costs and for inclining block rates when embedded costs are higher. Additionally, some jurisdictions have used this strategy to allocate additional, incremental resources to specific rate classes across all rate classes. There are two possible intended goals for this, depending on the trajectory of costs:[13]

- To act as a foundation for taxing fast-growing classes with high growth costs while shielding slower-growing classes from these additional expenses
- To build a base for the expanding class to receive the advantages of new, inexpensive resources

When costs are being driven by uneven growth among customer classes, this method of treating incremental resources differently may be useful. For instance, in the 1980s, commercial loads in the United States increased significantly more quickly than residential loads, and this method might be used to allocate the expense of pricey new resources to the classes responsible for those new costs.

1.3 Categorizing Customer Costs

1.3.1 Direct Assignment

Direct assignment costs are costs that can be solely identifiable and applicable to a specific customer or customer class since these costs are associated with providing a service to a particular customer. For example, these include customer-dedicated transmission radial lines or dedicated distribution substations. Another example is street lighting facility costs. Because streetlighting O&M costs are closely related to the streetlighting class of consumers, they qualify as direct assignment costs.

[13] Ibid.

Direct cost assignment can also be suitable for equipment necessary for specific customers and not shared with other customer classes or double-counted in common costs. Examples of such equipment and plants include distribution-style poles that support streetlights and conductor spans to such poles. Another example would be short tap lines from a main primary voltage line to supply a single primary voltage customer's premises, which are equivalent to a secondary distribution service drop. Beyond a few exceptions, determining whether distribution equipment (such as wires and poles) was created for or presently serves just one customer class and ensuring that the customer class is appropriately credited is neither practicable nor effective.[14]

Direct cost assignment is always the optimum method for allocating expenses to customer tariff classes and should be utilized if there is a direct relationship between costs and the service supplied to specific customers. However, only small amounts of costs can be allocated directly because most costs are incurred by a utility to jointly serve many classes of customers.[15]

1.3.2 Joint Costs

Joint costs are the cost incurred in conjunction with two or more types of activities, where each activity does not have its own incremental cost function. In the electric utility sector, generation, transmission, and most distribution facilities work together to serve a large number of customers. One example of such a joint cost is an electricity generating plant that produces electricity jointly for several customers. These customers have a wide range of characteristics, requiring service at varying rates and with varying consumption patterns throughout the day, month, and year. As a result, relatively few costs in the utility business can be properly attributable to specific consumers or customer groups.

There are few costs that may be allocated to a certain client or customer class, for example a substation or other facility that provides service exclusively to a large industrial plant, military base, or special contract customer. However, the majority of the utility's expenditures must be assigned to customer classes using an allocation procedure that fairly allocates charges based on cost causation.[16]

1.3.3 Common Costs

Common costs are incurred when an entity produces several services using the same facilities or inputs. They are common to all rate classes but not directly connected to any single class.[17] Overhead expenditures, such as the utility's management salaries or accounting and legal fees, are examples of costs that are common to all of the utility's distinct services.[18]

In an embedded cost analysis, the classification and treatment of joint and common expenses needs substantial judgment. The joint and common costs identified in the test year are allocated in an embedded cost study either 1) on the basis of the overall ratios of those costs that have been directly assigned, 2) a series of allocators that best reflect cost causation principles such as labor, wages, or plant ratios, or 3) by a detailed analysis of each account to determine its usefulness.

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[14] "Electricity Utility Cost Allocation Manual." NARUC. 1992, https://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD

[15] Electricity distribution functionalization, classification & allocation guidelines for the municipal electric association." Ontario Energy Board. https://www.oeb.ca/documents/cases/RP-2003-0228/costallocation_guidelines_150705.pdf

[16] "Overview of electric cost of service studies." The Prime Group. 2012. http://www.theprimegroupllc.com/COSS_Overview.pdf

[17] "Primer on Rate Design for Cost-Reflective Tariffs." USAID & NARUC. 2021. http://pubs.naruc.org/pub/7BFEF211-155D-0A36-31AA-F629ECB940DC?_gl=1*922y33*_ga*MTA0Njg4Njk4Ni4xNjYyMTIyODc0*_ga_QLH1N3Q1NF*MTY4MDAzNzE5Ni45Mi4wLjE2ODAwMzcxOTYuMC4wLjA.

[18] "Electricity Utility Cost Allocation Manual." NARUC.

In a marginal cost study, the variance of common expenses that change with production is brought into the analysis using regression techniques and becomes a multiplier to the marginal cost per kilowatt (kW) or kWh. Since many common costs do not alter with changes in production, marginal cost studies include less joint and common costs than embedded cost studies. The inclusion of variable and non-variable joint and common costs leads to the disparity between the totals generated from a marginal cost analysis and the revenue need based on the embedded test year costs.[19]

1.4 Attributing Customer Costs by Function

1.4.1 What is Functionalization?

Functionalization is the process of assigning company revenue requirements to specified utility functions.[20] In other words, it is the separation of cost data into the functional activities performed in the operation of a utility system (i.e., power supply, transmission, distribution and customer service).[21] Besides, there are joint, common costs (in addition to the functionalized costs), which are spread to each functional category based on the relationship of the joint cost to the business function. For instance, such costs include A&G costs. Costs must be first functionalized because each class's service requirement tends to have various relative impacts on each service function. Accordingly, it is necessary to develop separate sub-parts of the total revenue requirement for each function (and in some cases sub-function).[22]

1.4.1.1 Description of the Process of Separation of the Total Revenue Requirement into Functional Components Related to the Operational Activities of the Utility

The revenue requirement is the amount of funding that is needed by a utility to cover its capital expenditure (Capex) and operational expenditure (Opex). Utilities and regulators make a great number of significant decisions in the process of setting the revenue requirement, including establishing the historic or forecast "test year" used to check whether cost estimates are valid. Some states in the United States treat rate cases in phases, starting with the setting of the revenue requirement, then followed by a second phase for regulatory approval of rate structure.

After the revenue requirement has been set, the subsequent stages, as well as the rate design process, become a zero-sum game: costs that are not allocated to certain customers must be allocated to others. Functionalization is the first stage in breaking down the approved revenue requirement into its component parts to draw conclusions about cost causation. In the United States, functionalization follows the categories set in the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts (USOA). That is, capital and operating costs are categorized based on whether they relate to the power generation (or "production"), transmission, distribution, customer service, or A&G functions.[23]

Standard Functionalization Method

As stated above, plant investment costs or rate base are normally functionalized into such cost categories as: production, transmission, distribution, and general cost. The fact that costs for the different functions are readily identifiable and rate base accounts are maintained by functional categories makes the functionalization of rate base very straightforward. Expense accounts are also

[19] "Electric Utility Cost Allocation Manual." NARUC.

[20] Ibid.

[21] "OPALCO's Cost of Service Analysis and Rate Design Process." OPALCO. 2014. https://www.opalco.com/wp-content/uploads/2015/04/Rate-Design-COSA.pdf

[22] "Class Cost of Service Study and Selected Rate Design." Xcel Energy. 2015. https://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/2016-MN-Rate-Case/MN-Rate-Case-2016-Volume-2E-5-of-6-Class-Cost-of-Service-Study-Peppin-Testimony.pdf

[23] "New Uses for an Old Tool: Using Cost of Service Studies to Design Rates in Today's Electric Utility Service World." EQ Research. 2017. https://www.ourenergypolicy.org/wp-content/uploads/2017/04/New-Uses-for-an-Old-Tool-FINAL.pdf

normally kept according to these basic functional categories, with expense items associated with certain types of plant being treated the same way as the corresponding plant account.

The areas where there usually are differences in functionalization among utilities are the treatment of general plant and A&G expenses. Normally, general plant is assumed to be a separate functional category. In some cases, when internal accounting systems are able to support such an assignment process, utilities will record general plant investment by assigning the costs into other functional categories (like an overhead assignment or a form of activity-based accounting). On the expense side, the way A&G costs can be treated is the same. Typically, they are treated as a separate expense category that can be spread to functions based on other O&M expenses.

Normally, in the United States, for a distribution cooperative, the functionalization process is relatively straightforward since the USOA may be relied upon to accurately state the function that each cost category performs. For those more general accounts where the function may not be readily apparent (e.g., A&G), the functionalization process may be combined with the classification process.[24]

1.4.2 Allocation of Customer Costs by Function Using Embedded COSS

According to the traditional model, functionalization identifies the purpose served by each cost (or the underlying equipment or activity), classification identifies the general category of factors that drive the need for the cost, and allocation selects the parameter to be used in allocating the cost among classes. Despite the convenience of such organization of a COSS, functionalization and classification decisions are not necessarily crucial to the final class cost allocations. The COSS can reach the same final allocation in several ways.

For instance, consider the reality that a portion of transmission costs is driven by the need to interconnect remote generation to avoid fuel costs. This can be reflected by functionalizing a portion of transmission cost as generation, classifying a portion of transmission the same way as the remote generation, or recognized using a system-wide transmission allocator with some energy component. In any case, a portion of costs is allocated based on energy throughput, not solely on design capacity or actual capacity utilization.[25]

According to the more experienced embedded cost studies approach, baseload and peaking resources are treated very differently: baseload resources are assigned to loads in all hours, and peaking resources are assigned only to peak hours. Time-differentiated embedded cost studies include methods such as the base-intermediate-peak method, the peak-credit method, and the equivalent-peaker method. All three approaches treat assets used to serve baseload usage that occurs year-round very differently from peaking resources. Because gas-peaking power plants are typically built close to cities, they do not require the same transmission capacity as baseload units. Demand response programs used to serve the highest load 10-50 hours per year normally require no generation or transmission investment, and no fuel costs at all.[26]

1.4.2.1 Generation

According to international practice, a vast number of regulators have recognized that energy needs are a significant driver of generation capital investments and non-dispatch O&M costs. In modern utilities, generation facilities are built for two main purposes: to serve demand (i.e., to meet capacity

[24] "Developing Rates for Distributed Generation." National Rural Electric Cooperative Association. 2001. https://www.cooperative.com/programs-services/bts/Documents/DG-Toolkit/RatesForDistributedGeneration.pdf
[25] "Electric Cost Allocation for a New Era: A Manual." Regulatory Assistance Project (RAP). 2020. https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf
[26] "Dividing the Pie: Cost Allocation, the First Step in the Rate Design Process." Regulatory Assistance Project (RAP). 2015. https://www.raponline.org/knowledge-center/dividing-the-pie-cost-allocation-the-first-step-in-the-rate-design-process/.

and reliability requirements), and to produce energy economically. The amount of capacity is largely determined by reliability considerations, but the selection of generation technologies and thus the cost of the capacity are largely determined by energy requirements.
For variable renewables (wind and solar), the effective capacity of the generators is much smaller than their nameplate capacity, and the costs are mostly undertaken to provide energy without fuel costs or air emissions. Energy storage systems provide both energy benefits (by shifting energy from low-cost to high-cost hours) and reliability benefits, while demand response is used primarily to increase reliability.

A wide number of utilities and regulators suppose that a great portion of generation investment and non-dispatch O&M costs is incurred to serve energy requirements. There are two categories of approaches in terms of classifying these costs as energy-related and demand-related. First, average-and-peak is a top-down method that uses high-level data on system loads and costs. Second, there is a range of bottom-up approaches that check the drivers for costs on a plant-specific basis: base-peak and related methods; the equivalent peaker method; and operational characteristics methods. Normally, the bottom-up approaches are preferable for classifying generation costs. The average-and-peak approach is well suited for shared distribution system costs.[27]

Energy-classified generation costs are usually allocated to all classes in proportion to total annual class energy consumption. Such costs can also be calculated by time period and allocated to classes in proportion to their usage in each time period. Assigning costs to time periods is usually straightforward for fuel and dispatch O&M. The energy-related capital investment and non-dispatch O&M costs can be allocated to classes in proportion to energy or assigned among time periods in proportion to the fuel and dispatch O&M.

Generally, demand-related generation is allocated based on class contribution to system peak loads, referred to as CP. The loads which determine how much capacity a utility requires can be concentrated in a few hours a year, a few hours in each month, the highest 50 or 100 hours in the year, or some other measure of the loads stressing system reliability.

Before having access to the kind of developed hourly data utility workers and management staff can obtain today, they have tended to allocate demand costs on a single annual CP, the average of the four monthly peaks in the high-load summer season, the average of some number of summer and winter monthly peaks, a defined number of peak hours when peaking resources are expected to operate, or the average of the 12 monthly peaks. The number of months included in the computations of the demand allocator often reflects the following factors:

- The number of months during which the system may experience its annual peak load
- Whether high loads occur in both summer and winter
- Whether requirements for maintenance outages reduce available capacity in off-peak months enough that available reserves in those months are comparable to the reserves in the peak months

1.4.2.2 Transmission

Investments in transmission lines and substations are of significant importance for a wide assortment of purposes, including integrating inherently remote generation, allowing economic dispatch of generation over large areas, and providing backup reliability. Any particular transmission line and the substations to which it is connected may perform multiple functions under varying load and generation conditions. The allocation methods used may need to distinguish among several categories of transmission, due to the fact that the purposes for constructing transmission and the use of the facilities vary so widely.

[27] "Electric Cost Allocation for a New Era: A Manual." Regulatory Assistance Project (RAP).

The generation-related portions of transmission equipment (e.g., switching stations, substations and transmission lines required to tie generators into the general transmission network, etc.) are often functionalized as generation. In the United States regions with FERC-regulated independent system operators (ISOs) or regional transmission organizations (RTOs), state regulators may not have authority to determine the amount of bulk transmission cost a local distribution utility must pay. Therefore, such states can allocate costs among classes in a way similar to what FERC uses to allocate costs among utilities and other parties. States also have the authority to allocate that cost using a different method than FERC uses for wholesale market allocation.

The hours of maximum transmission loads may be different from the hours of maximum generation stress. That is, the power lines from remote baseload units to the load centers can be most heavily loaded at moderate demand levels. At high load levels, more of the low-cost remote generation may be used by load closer to the generator, while higher-cost generation in and near the load centers increases, reducing the long-distance transmission line loading.

1.4.2.3 Distribution

Distribution costs are all incurred to deliver energy to customers and are primarily investment-related costs that do not vary in terms of load in the short-term. One of the key issues in cost allocation is the determination of the portion of distribution cost that is related to primary service as opposed to secondary service. Traditionally, distribution costs are divided up as either demand-related or customer-related, but some modern methods can fairly allocate a substantial portion of these costs on an energy basis.

According to traditional studies, a large portion of the distribution grid is classified as demand-related. However, a newer hourly allocation method may skip this step, and assign distribution costs to all hours when the asset (as well as a portion of the cost of the asset) is required for service. For demand-related costs, class customers' noncoincident peak (NCP) is commonly, but usually inappropriately, used for allocation. This allocator would be suitable only if each component completely served a single class, if the equipment peaks occurred exactly at the time of the class peak, and if the sizing of distribution equipment were due solely to load in a single hour. Contrarily, most substations and many feeders serve several tariffs, in various classes, and many tariff codes.

In other words, customers in a single class, in different areas and served by different substations and feeders, may experience peak loads at different times. Therefore, the peaks for distribution equipment do not necessarily align with the class NCPs. For instance, even if all the major classes are summer peaking, some of the substations and feeders may be winter peaking, and the opposite way. Even within a season, substation and feeder peaks will be distributed to many hours and days.

Ideally, the allocators for each distribution plant type would reflect the contribution of each class to the hours when load on the distribution equipment contributes to the potential for overloads. That allocation could be constructed by assigning costs to hours or by constructing a special demand allocator for each category of distribution equipment. If such detailed allocation is too complicated, the cost allocators should still reflect the fact that distribution costs are driven by load in many hours. For many utilities, additional information on system loads is critically important for cost allocation, planning, operational, and rate design purposes. Particularly, utilities should aim to understand when each feeder and substation reaches its maximum loads and the mix of rate classes on each feeder and distribution substation.

1.4.2.4 Billing/Customer Service

Utilities often classify customer service and information expenses as customer-related and allocate them in proportion to customer number. This approach is inappropriate, because these expenses are more likely to vary with class energy consumption and revenues. Normally, larger customers have more complex installations, and metering and billing and require more time and attention from a utility. Hence, a utility customer service staff does not spend as much time and attention on each residential customer as on each large commercial or industrial customer. Thus, the billing costs should be weighted proportionately to the customer classes with complex arrangements. The alternative to a simple customer allocator for customer service costs may be to use a weighted customer allocator, which implies that larger customers are assigned a multiple of the costs assigned to smaller customers.

Sales and marketing costs are often unreasonably allocated by the number of customers rather than the purpose of sales and marketing expenses. Since the purpose of these costs is to increase contributions to margin from new or existing customers, thereby reducing the need for future rate increases, the costs should be allocated by base rate revenue or another broad allocation factor such as rate base. Some sales and marketing funds are used to promote important public policy programs (for example, energy efficiency or electric vehicles). Nonetheless, other sales and marketing efforts may promote programs that ratepayers should not fund at all (e.g., promotion of inefficient electric resistance heating by a utility that is almost entirely fossil fuel-based) and should be checked closely in revenue requirements cases.

1.4.2.5 General Overhead Expenses

Utilities also have a wide variety of overhead 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 expenses due to regulatory proceedings. The common thread is that these costs support all functions of a utility.

Office space
In performing the COSS, O&M expenses for production, transmission, distribution, customer accounting, and customer information have already been functionalized, classified, and allocated. Therefore, the amount of labor, wages, and salaries assigned to each function is known, and a set of labor expense ratios is thus available for use in allocating accounts such as transportation equipment, communication equipment, investments, or general office space.[28]

Computers, technology, communications equipment
According to the embedded cost-of-service approach, these costs are included in the "shared distribution" costs. That is, the supervisory control and data acquisition equipment that monitors the system operation and records system data. This is a network of sensors, communication devices, computers, software, and typically a central control center. All shared distribution costs should be apportioned based on the time periods when customers utilize these facilities. The system is needed to provide service at every hour, and in most cases a sizable portion of the distribution system cost should be assigned volumetrically to all hours across the year.

Pensions
Some of the A&G accounts in the standard utility accounting systems serve a single function and are driven by a single factor. For instance, employment taxes, pension expenses, and other employee benefits vary with the number of employees and salaries and are generally functionalized in proportion to the labor in each function. Or they are allocated using the special labor allocation factor calculated earlier in the process, based on how the labor costs in each function were previously allocated among the classes. If a labor allocator is not available, nonfuel O&M is often used as a reasonable proxy for labor.

[28] "Electric Utility Cost Allocation Manual." NARUC.

Legal and regulatory expenses
In terms of cost causation, the regulatory assessment covers expenditures on many kinds of proceedings, including (depending on the jurisdiction) rate cases, resource planning, project certification, review of investments, power purchase contracts, and fuel expenses. Demand and energy use are the major contributors to the size of the assessment and the cost of its regulatory efforts. Depending on the jurisdiction and the distribution of the regulator's efforts, the most equitable allocator may be class revenues or energy consumption. Many utilities allocate these costs by base rate revenues. A more appropriate allocator would be total revenues, given that fuel and other costs collected in riders are also regulated and planning and certification activities related to the rider costs constitute a significant portion of the burden on regulators.

In the future, organizing costs by function will probably still be helpful in organizing thinking about cost causation, but the COSS may need to differentiate functions in new ways. For example, distributed generation, storage, energy efficiency, demand response, and smart grid technologies can provide services that span generation, transmission, and distribution.

1.4.3 Allocation of Customer Costs by Function Using Marginal COSS

The key principle of the marginal cost approach is that economic efficiency is served when prices reflect current or future costs (e.g., the true value of the resources being used to serve customers' loads [rather than historical embedded costs]). This is a significant underpinning that most analysts agree on, but there are serious theoretical and computational complications associated with the development of marginal costs.

Marginal cost studies start from a similar functionalization as embedded cost studies: generation, transmission, and distribution. However, the data used are not identical to those used in an embedded COSS. The typical marginal COSS requires detailed hourly data on loads by customer class, marginal energy costs, and measures of system reliability (e.g., loss-of-energy expectation, peak capacity allocation factor, probability of peak, etc.), as well as multi-year data on loads and investments for the T&D system.

As it was mentioned before, some of the key issues associated with marginal cost analysis, in general, are:

- Mixed time horizons. Marginal cost methods often mix short-run, intermediate-term, and long-run marginal costs in an inconsistent manner.
- Obsolete technique in terms of changing resource options. Either short-run or long-run marginal energy and generation capacity cost allocation methods essentially have been designed for fossil-fueled systems, using economic dispatch. Renewable resources, storage, and other resources tend to decrease the short-run prices of fossil-fueled energy and existing fossil-fueled capacity.
- Treatment of renewables. With the substitution of renewables with relatively high capital costs but almost zero variable costs for fossil fuel, short-run marginal energy costs are significantly below the cost of new generation, with significant implications for cost allocation. For instance, a wind plant that runs at 40% to 50% capacity factor depresses short-run marginal energy cost and thus may have no impact on capacity costs.

1.4.3.1 Generation

As mentioned above, the first important question regarding marginal generation costs is the balance between short-run and long-run marginal costs. There are two options for explicitly calculating long-run marginal costs. Both are based on the cost of building and operating new resources. The first option is the use of long-run marginal costs (referred to as long-run incremental costs by the entities that developed these methods) to allocate generation costs based on plant types. This method was developed in North America, where large portions of the systems were energy-constrained. According to this approach, the cost of new baseload generation in a resource plan was calculated as the total marginal generation cost. The cost of peaking generation was determined to be the peak cost, and the remaining costs were energy related. In the past, the baseload generation cost was often a coal plant.

Short-run marginal energy costs are usually calculated from a production cost or similar model on a time-differentiated (or even hourly) basis. These calculations are made over a relatively short period (typically one to six years out, depending on the utility).

According to the short-run marginal cost method, the theory is that the value of generation capacity is capped at the least cost of acquiring generation for reliability. If all that were needed was capacity, a cheap resource to provide capacity (such as a peaking plant) could be built. Any more expensive generation would have been built specifically to reduce total system costs (fuel plus capacity). According to this approach, the cost of the peaker is multiplied by the real economic carrying charge, and O&M and A&G costs are added to it.

1.4.3.2 Transmission

In the United States, marginal transmission costs have not received the attention that marginal generation and distribution costs have received. The reason is that in large parts of the country, transmission is partly if not wholly under FERC jurisdiction.

The long-run marginal cost method for marginal transmission costs involves some analysis of the relationship between transmission system design and peak loads. On the other hand, the original method involves regression analysis between cumulative investment in load-related transmission (calculated in real, inflation-adjusted dollars) and cumulative increases to peak load; two other methods have been developed. The first, the total investment method, examines total investment divided by the change in peak load. And the second, the discounted total investment method, uses discounted total investment divided by the discounted change in peak load.

The long-run marginal cost method essentially ignores large parts of the transmission system and therefore generally ends up with marginal transmission costs well below embedded costs. It also fails to recognize that peaking resources and storage are often strategically located near loads where transmission is constrained to reduce the need for transmission.[29]

1.4.3.3 Distribution

The most controversial issue for the calculation of marginal distribution costs is identical to the embedded cost studies: whether a portion of the shared distribution system (particularly the poles, conductors, and transformers) is customer-related or not. The marginal cost of distribution capacity can be developed for the whole distribution system, as well as separately for lines and substations. Using all of the distribution planning areas is so granular that it would be difficult to check and audit the relationship of costs to cost drivers. This is partly true because costs are dependent on the amount of excess capacity in local areas.

Additionally, customers that are large relative to the distribution system may never pay for the capacity needed to serve them in some cases. And customers in slow-growing areas are charged less than those where load is growing faster, even if those customers are using a significant portion of the distribution system. Some distribution costs that are similar to replacement costs are actually policy-related and might not be marginal costs as a result (e.g., urban undergrounding of overhead lines, other

[29] "Electric Cost Allocation for a New Era: A Manual." Regulatory Assistance Project (RAP).

changes related to safety and environmental protection). Distribution marginal costs end up with tricky calculation issues because of differences in the determinants on which marginal cost calculations are made and the costing determinants on which revenue allocation is conducted.

1.4.3.4 Billing/Customer Service

A marginal cost analysis of billing and customer service expenses is usually done in one of two ways. The most common method is to average costs over a number of historical and projected years. These costs are calculated per weighted customer, recognizing that certain activities are more heavily related to some customers than others. The second approach is to use the costs of revenue cycle services, which are short-run incremental costs used to pay competitive service providers, plus similar short-run calculations for call centers and other activities.

The frequency of billing and collection is driven by usage. If customers used minuscule amounts of power, it would not be cost-effective to read meters (without smart meters) or even bill on a monthly basis. For utilities without AMI, costs in excess of bimonthly meter reading and billing could be considered revenue-related rather than related to customer accounting.

Relatedly, if smart meters are being implemented or have recently been implemented, meter reading costs from periods before smart meter implementation (as well as other costs such as call center costs associated with the implementation process) must be removed to prevent double counting of the capital cost of the smart meter and the operating cost of the mechanical meter that the smart meter replaces. As with embedded costs, the costs associated with major account representatives assigned to serve large customers should be considered part of the marginal costs of serving those customers and should be assigned to them.

In some cases, the difference between marginal and embedded cost analysis is that costs are excluded from marginal costs while being allocated differently from other costs as embedded costs. Some examples are economic development rates and uncollectible accounts expenses. Economic development rates, as well as any costs for marketing and load retention, are not marginal costs.

Uncollectible accounts expenses are not marginal costs associated with current bill-paying customers and conceptually should not be included in marginal costs. If uncollectible accounts are included, then late payment revenues must be treated consistently by adding them to the distribution revenues to be allocated and subtracting them from the classes that pay them.

Lastly, a number of cost elements that are sometimes mistakenly classified as customer service do not fit a marginal cost analysis well, particularly if the programs are undertaken for public policy reasons. A cost undertaken for public policy reasons is not a marginal cost, even if it might theoretically vary with the number of customers. An energy efficiency program or demand response program is established by the state or regulators for policy reasons, in theory, to provide a cost-effective or environmentally preferred substitute for other investments and expenses. Subsidy programs for low-income customers are also established for policy reasons. Certain other programs are also policy-related, such as promoting solar energy, battery storage, and electric vehicles; allowing customers to opt out of smart meters; and research and development programs.

1.4.3.5 General Overhead Expenses

Both A&G expenses and general plant costs are typically considered "loaders" to marginal costs, and are applied to the generation, transmission, and distribution functions. Fundamentally, at least some A&G expenses and general plant costs are marginal costs, though over varying time horizons and in varying amounts because of economies of scale in running a large corporation.

Short-run marginal costs include at least workers' compensation and pensions and benefits associated with other marginal costs that are labor-related. Similarly, incentive pay, to the extent recorded to A&G accounts, is a short-run marginal cost assigned to labor. Property insurance is a plant-related marginal cost to the extent that the amount of insured property affects the premiums. If longer-term A&G costs are included, one can either include all of them as variable in the long run with the size of the utility or recognize potential economies of scale, which would mean that only a portion of costs is marginal.

The best example of an intermediate-term marginal cost is the human resources department, which varies with the size of the workforce. Other examples of costs that will vary with the size of the utility in the intermediate term are benefits administration, accounts payable, payroll processing, and capital accounting. Over a longer period, portions of an even broader set of costs are variable. For example, executive salaries are related (though possibly not proportional) to the size of the company, as a larger company will have more executives and pay them more. Other examples relate to buildings and other general plant items. A utility with fewer workers will own, rent, and maintain less building space and have fewer vehicles and tools.

Recently a number of utilities in the United States, following the FERC method of unbundling transmission, have allocated both A&G expenses and general plant costs (using a long-run marginal cost basis) based on labor with the exception of property insurance, which is based on plant; and franchise fees based on revenue. The labor allocation method for A&G expenses tends to be less favorable to small customers than the plant-based method, but it has analytical merit. Key issues here are ensuring that specific elements of A&G expenses are truly recurring marginal costs; and whether a given cost should be functionalized differently among generation, transmission, and distribution.

1.5 Attributing Customer costs by Classification

This section covers the process of allocating the functional costs by the primary cost drivers.

1.5.1 The Main Cost Classification Categories

Traditionally, costs can be categorized as demand-related, energy-related, or consumer- or service-related.

1.5.1.1 Demand-related Costs – kW for Peak Capacity Needs

The phrase "demand-related cost" dates to a time when utilities lacked detailed information on how each customer or class of customers used their services throughout the day. This phrase was frequently used to refer to the total capital and operational expenditures of all generating, transmission, and shared distribution facilities, as well as to the percentage deemed essential to meet peak demand.[30]

The fixed expenses associated with the plant in service are typically demand costs. Electricity's peak usage is reflected in the rate base and expenditure categories. Demand-related costs are distributed among the customer classes in accordance with the demands (kW) imposed on the system during specified peak times. This category includes most of the generation and transmission supply infrastructure. According to the class's concurrent demand during the utility system's peak period, demand costs are often distributed among different customer classes. Depending on how the utility company operates, the range for CP could be from a 1 CP to a 12 CP.[31]

[30] Lazar, J. "Smart Rate Design for a Smart Future, Appendix A." Regulatory Assistance Project (RAP). https://www.raponline.org/wp-content/uploads/2016/05/appendix-a-smart-rate-design-2015-aug-31.pdf
[31] Lazar, J., Chernick, P., Marcus, W., and LeBel, M. "Electric cost allocation for a new era: A manual." Regulatory Assistance Project (RAP).

1.5.1.2 Energy-related Costs – kWh of Energy Generated

Generally speaking, energy costs are variable costs. Depending on how much energy (kWh) the system must supply to serve the consumers, they are distributed across the various customer classes. A kWh total utilized over a given period are things included in the rate base and expenses. Fuel and operation/maintenance costs are frequently included in energy costs. The distribution of energy costs among the classes is determined by comparing the energy consumption of each class with the sum of all class energy usage. For instance, if residential clients utilize 33% of the entire amount of energy consumed, the residential class will be charged 33% of the total amount for all energy-related expenses.

1.5.1.3 Customer-related Costs – Number of Customers

Typically, customer costs are fixed costs. According to the number of consumers in each class, customer costs are divided among them. These expenses, like meter charges or service drops, are directly tied to a specific customer using a utility. The meters and customer services costs are good examples of customer-related costs.

1.5.2 Examples of Demand-related Costs

This section covers some of the examples of demand-related costs according to three main categories: generation capacity costs, transmission lines costs, and distribution lines and transformer costs.

1.5.2.1 Generation Capacity Costs

The amount of capacity needed by a utility system, which is typically expressed in megawatts (MWs) or gigawatts at the time of the CP of the system, determines whether the utility should retire existing plants, add new resources, postpone planned retirements, or maintain the system as is. Although the typical planning techniques currently employed by utilities and ISOs have frequently achieved their initial goals of determining the least-expensive resources available at the utility system level, these techniques frequently oversimplify critical elements of overall capacity and reliability issues.

The fundamental tenet is that costs associated with reliability are not all “caused” by a single hour or a few hours of demand over the year. A system must always be capable in some way and to some degree. The type of capacity and the location of that capacity affect the value of capacity in some ways. Although the required capacity (measured in MWs) depends on demand in a certain period and the properties of the power plants, the cost of capacity (measured in dollars per MW-year) is mostly influenced by energy needs.

A combustion turbine was often regarded as the least expensive type of capacity to meet peak needs in the previous millennium. Although these units were inefficient and frequently consumed more expensive fuels, they had low initial investment costs and low recurring O&M expenditures. These qualities made them ideal for short-term reliability requirements such as irregular operation during peak hours. On the other hand, it made sense to make significant investments in equipment with high upfront costs, high efficiency, and low fuel prices and to operate this equipment almost all year round. Instead of peak loads, year-round energy requirements were what drove these significant investments.

In the modern world, a generating unit may not be the most affordable kind of capacity to meet excessive peak loads. Demand response, customer reaction to crucial peak pricing, or battery storage may be the least expensive resource to serve a very short-duration peak, also known as a needle peak, for very low-duration loads. When an end-use load can be reduced, it saves not just the capacity that the reduced load represents but also the marginal line losses and reserves needed to sustain it reliably. Similarly, the use of distributed energy resources (DERs) eliminates the need for line losses to transport generated capacity to that site.

1.5.2.2 Transmission Line Costs

Transmission line costs are influenced by the length of the lines, the terrain they must travel through, and the amount of electricity they must transport at various times, occasionally in both directions. Many transmission lines can be used to their full capacity at any time of the day or night, and their usage patterns can fluctuate dramatically over time. Larger conductors, more conductors, and/or higher voltages are required to carry more power, which all raises the cost of the system. For environmental reasons, to make fuel access easier, reduce land costs, and avoid conflicts between different land users, generation may be located far from the load. For the utility to use the least expensive mix of generation at all load levels, it may be necessary to build more transmission. Generation plants also frequently vary widely in terms of fuel cost, efficiency, and flexibility.

Contrarily, without the need for new transmission, demand response, energy efficiency, and energy storage can be very precisely targeted geographically to supply the necessary capacity in a particular location. The cost and size of transmission are also impacted by the energy load over a long period of time. The length of peak loads and the rate at which loads decrease from peak to off-peak periods have an impact on the sizing of underground lines since underground transmission is particularly sensitive to the build-up of heat around the lines.

When compared to an eight-hour peak with a high daily load factor, a 15-minute peak following a day of low loads may allow an underground line to handle twice as much load. Utilities must install larger cables or more cables than they would for shorter period loads to decrease losses and the accumulation of heat from frequent high loads.

With high load factors, the transformers are at or close to full loads for a significant portion of the year. The transformer needs to be sized appropriately in this situation to keep overloads at manageable levels and a frequency consistent with a fair estimated lifespan for the asset. The transformer will fail more quickly if it frequently experiences overloads and operates close to capacity.

Transmission lines perform a variety of functions, including linking distant power plants to urban areas and facilitating the most efficient exchange of power between regions with various load profiles and generation possibilities. It is possible to assess and allot each transmission segment separately on a cost-reflective basis.

1.5.2.3 Distribution Line and Transformer Costs

The same elements that affect transmission costs also affect load-related distribution costs. Distinctive components are made and sized for various purposes. While some are made to meet the needs of hundreds or thousands of customers, others are made to meet the needs of just one. If there are more high load hours per year and if the daily load factors are high, substations and line transformers must be larger, or they will wear out more quickly. Heat accumulation from prolonged, intensive use can have negative effects on underground and above feeders.

Thermal and permissible voltage drop restrictions together define the maximum load that can be placed on distribution lines. Upgrades (raising the feeder voltage, adding a new feeder, reconductoring to a larger wire size, or switching from single-phase to three-phase supply) may be necessary to maintain an optimum voltage at the end of a primary feeder when there are more loads on it. In comparison with large customers, small secondary customers can be served with smaller conductors and can be located further away from the line transformers, allowing the utility to employ fewer transformers to serve the same load.

Similar to station transformers, line transformers can withstand modest overloads for a few hours but will quickly degrade under prolonged overload situations. As a result, while sizing transformers, the underlying load shape is considered in addition to the maximum capacity needed. The necessity to service a certain geographic area is what drives a significant percentage of the distribution investment. The incremental cost of adding more customers after deciding to establish a circuit is primarily made up of extra line transformers (if the new customer is segregated from others) and secondary distribution lines. This is true even if those investments, especially in urban and suburban regions, may benefit many clients. Instead of peak load or customer count, the overall income from the clients served functions as a major justification for these shared facilities.

Almost all electric utilities have a line extension policy that outlines how the expenses paid to expand service to additional customers will be split. Meters, which are normally installed for all residential and general service customers but not for particularly foreseeable loads like traffic signals or streetlights, are the last elements in the distribution system. The classification of the expense is up for discussion. On the one hand, a meter is required due to the fact that usage varies from customer to customer and month to month, a cost that is ostensibly tied to usage. On the other side, each metered customer needs their own meter, and expenses for meters within a class are often constant.

Smart meters allow for more accurate measurement and control of local loads as well as more accurate assignment of peaking capacity needs, but they also come with higher direct investment costs and back-office investments. Despite this, they benefit the generation, transmission, and distribution systems. The cost of current transformers and potential transformers, which are required to measure large consumers, should be included in their metering costs. This is a problem that both embedded and marginal cost techniques share.

1.5.3 Demand-related Cost Allocation Methods

There are several possibilities available for choosing the method for allocating demand-related charges, and these options could have a big impact on how much money is allocated to different types of consumers. The decision will be based on the study's aims, the utility's qualities, and the availability of data.[32]

1.5.3.1 System Peak Responsibility

To distribute demand-related costs, a variety of "demand" measures are used, such as various measurements of contribution to CPs (a single annual system CP, or 1 CP); the average of several high-load monthly CPs (e.g., 3 CP or 4 CP); the average of all 12 monthly CP contributions (12 CP); and the average of the class contribution to a certain number of high-load hours (e.g., 200 CP). The peak responsibility approach is a common name for using these peak-based demand allocators.

The largest demand imposed on the electric system at any one time is referred to as system peak demand. System peak demand can be measured over a whole interconnection, for specific utilities or service areas, or for subregions within an interconnection.

1.5.3.2 Non-Coincident Demand

The demand in MW for each category of customer, independent of when it occurs, is known as non-coincidental demand. The category's share of the system's maximum demand will be larger than or equal to this non-coincidental demand. As a result, the total of all such demand for each consumer group will be higher than the system's peak demand.

At the system level, utilities have irregularly distributed generating and demand expenses to the class NCP. The maximum class peak, maximum diversified demand, or another similar term is used to refer to the class NCP, and "NCP" is used to refer to the total of the individual customer NCPs within each

[32] "Category wise cost of service study for paschim gujarat vij company limited." Paschim Gujarat Vij Company Limited. 2020. https://www.pgvcl.com/Whatsnew/PGVCL%20-%20CoS%20Report-FY2018_19.pdf

class. This strategy would have been roughly acceptable for some utilities that served different classes with peak needs that occurred during different seasons. The class NCP would transfer demand charges to other classes based on their summer or winter peaks, but not on their contributions to either of the seasons' high-load hours Since combined system loads are what drives reliability calculations and the demand for generation capacity, some metric of the combined loads on the system is crucial.

1.5.3.3 Average-Excess Demand

Using components that incorporate the category average demand and excess demand, the average-excess demand approach distributes costs associated with demand to the consumer category. For a category, excess demand is defined as:

Category Excess Demand = Non-Coincident Demand – Average Demand

The allocation is based on two elements in the technique. The ratio of the category's average demand to the system's average demand multiplied by the system load factor is the first component, also known as the contribution to average.

*Contribution to Average = (Category Average Demand/System Average Demand) * System Load Factor*

The second factor, or contribution to excess, shows how much of the total excess demand across all categories is attributable to the category with the highest excess demand (non-coincidence peak demand minus average demand). The benefit of the strategy is that a category's CP demand is not necessary.

1.5.4 Examples of Energy-related Costs

Costs that are directly impacted by the quantity of kWhs a utility distributes over time are referred to as energy-related costs. Either fixed or variable costs apply to production facilities. Fuel costs, electricity purchases, and some O&M costs are examples of variable costs.

1.5.4.1 Fuel Costs

Most often, fuel costs are categorized as energy-related. They are divided up using the proper time-differentiated allocators, such as on-peak and off-peak kWh, or non-time-differentiated energy allocators (total kWh), which are determined by adjusting account for various line and transformation losses at various levels of the utility's T&D system. It may be essential to directly assign fuel costs to classes that are directly assigned the cost responsibility for certain generating units, depending on the cost-of-service technique employed.[33]

Renewable resources are replacing fossil fuel generation, substituting invested capital in place of variable fuel costs. Fuel costs per unit of energy generation are determined by the cost of the fuel used and the efficiency of the power source. This is frequently expressed as an efficiency percentage comparing the potential energy of the fuel input to the electricity produced, or as a heat rate expressed as the number of British thermal units of fuel input for every kWh of electricity produced. The technology needed to reduce emissions from dirtier fuels, such coal and oil, is expensive and capital-intensive. Additionally, each fuel has different costs associated with its supply, management, and disposal before use. For instance, it is necessary to dispose of nuclear waste and coal ash, both of which come with their own set of issues and expenses.

There are some plants that can be configured to use more than one fuel, primarily either natural gas or oil, including steam, combustion turbine, and combined cycle plants. Although there are a variety

[33] "Electricity Utility Cost Allocation Manual." NARUC.

of costs associated with such a dual fuel configuration, it enables the plant operator to select the fuel that is more affordable or adapt to other limitations.

1.5.4.2 Energy Purchases

Power purchase costs are determined to be demand- and energy-related since the utility must install or buy enough capacity to meet the system's peak demand in addition to being able to deliver the energy needed throughout time. Power purchase costs could be defined as fixed or variable cost.[34]

1.5.4.3 Generation Variable O&M Costs

O&M costs are divided into two types of costs: dispatch O&M costs, which may depend on the numbers of hours a facility generates, or non-dispatch O&M costs that can be incurred regularly on a monthly or annual basis. Costs for O&M that do not immediately correlate with energy output can be categorized and allocated using a variety of techniques. Costs are directly assigned if they are particularly connected to providing a certain rate class.

Using the proper demand and energy allocators, as well as ratio approaches, some accounts can be quickly classified as being exclusively demand- or energy-related. Based on the previous classification of O&M accounts to which these overhead accounts are associated, certain supervisory and engineering expenses can be categorized.

1.5.5 Energy-related Cost Allocation Methods

Costs associated with energy are distributed according to how much energy is used by different consumer classes. The energy used comprises allotted losses and sales to categories.

1.5.5.1 kWh of Energy Sold (Both at the Customer Meter and at Generation)

Energy-related costs are allocated to categories in the ratio of energy consumed. The energy consumed includes not only the sales (kWh of energy sold), but also the losses allocated to the respective categories. There is data that shows energy loads have a significant role in determining the costs of production plants. As a result, energy weighting may be applied to the treatment of production plant costs in cost-of-service analysis. Categorizing those costs to classes based on class energy consumption measured in kWh is one technique to implement an energy weighting.

Although sales to each class are readily available, allocating losses requires a great deal of discretion. The voltage at which a consumer category is connected has a significant impact on how technical losses are allocated. Prior to distributing technical losses, however, commercial losses are categorized. Then, the technical losses are distributed according to the category’s sales to commercial loss ratio.

1.5.6 Examples of Customer-related Costs

The costs of delivering services other than the provision of energy (e.g., metering, billing, collection, fault repair, etc.) are considered as predominantly consumer-related costs. Despite having a clear correlation with the number of consumers in a certain category, these expenses vary greatly amongst them.

1.5.6.1 Metering Costs

By identifying the requirements for the service, it is possible to examine the cost of meters and service drop investments individually by the kind of metering installation or by customer load class. While it

[34] “Category wise cost-of-service study for paschim gujarat vij company limited.” Paschim Gujarat Vij Company Limited.

would be conceivable to separate the demand and customer components of meter costs if it were assumed that the more sophisticated metering could be identified with higher levels of demand, all metering expenses are often invoiced on a per-customer basis; therefore, there is no need to make this distinction. The installed cost of each piece of equipment is multiplied by an annual carrying fee, and a factor to account for operating and maintenance costs is added.[35]

1.5.6.2 Billing and Account Processing Costs

Most utilities send monthly or bimonthly bills to their clients. The explanation for this is rather straightforward: billing less frequently would result in bills that were very high and difficult for some customers to pay; billing more frequently would result in billing costs that were an unacceptable percentage of the overall cost. Billing closer to when the product is consumed gives clients a better insight of their usage trends from month to month, which may help them become more productive. There are some exclusions: numerous water, sewer, and even electric utilities that provide service to seasonal residences could only issue invoices once or twice a year.

Customer service and information costs are frequently classified as customer-related expenses by utilities and allocated in proportion to a customer base. This strategy is unworkable since these costs are more likely to vary depending on the revenue and energy consumption of the class. It is crucial to take note of these cost drivers when classifying billing costs. From the perspective of cost causation, the reason for frequent billing is that utilization determines the cost.

1.5.6.3 Customer Connection Costs

The service drop, meter, final line transformer, and any secondary distribution lines that are not networked with other transformers are all included in the customer connection costs, also referred to as the point of delivery cost. Although some utilities include either line extension expenses or some sort of minimum system as customer fees, primary lines are normally not a point of delivery cost. Although some states also incorporate a transformer, the service and meter make up the bulk of the basic customer method. Calculations must be done to establish a meter cost for each class of client. Customers also force the utility to pay for billing, collections, and other related expenses.

1.5.7 Customer-related Cost Allocation Methods

There are two common types of methods for allocation of customer-related costs: 1) the basic customer method that focuses on number of customers, and 2) weighted average for number of customers.

1.5.7.1 Number of Customers

Generally referred to as the basic customer method, only costs that genuinely fluctuate with the number of customers should be treated as customer-related. In this method, costs are properly allocated between classes of customers based on the number of customers. The basic customer method classifies the entire common distribution network as demand- or energy-related, whereas only customer-specific plants are considered customer-related.

This would simply be the typical meter and some service drop expenses for relatively dense service regions in cities and suburbs. Customer-specific plants may include a share of transformer costs and the percentage of the primary system that consists of line extensions to specific customers in relatively sparsely populated areas, especially rural cooperatives. The basic customer method has been mandated or adopted by several jurisdictions in the United States, occasionally incorporating a percentage of transformers in the customer cost.

[35] "Electricity Utility Cost Allocation Manual." NARUC.

1.5.7.2 Weighted Average for Number of Customers

A weighted customer may be used as an alternative to a simple customer allocator for customer service costs. An analysis of the relative amounts of customer-related costs (e.g., service lines, meters, meter reading, billing, etc.) per customer is typically used to weigh the number of customers in each class. Each number in the data set is multiplied by a predefined weight before the final computation is completed when calculating a weighted average.

Weighting variables consider variations in customer features within or between groups. For example, we might wish to give rural customers in a class greater weight than urban customers when it comes to a certain plant account. The metering account is a good illustration of an account that needs weighting to account for class differences.

1.5.8 Approaches to Demand/Customer Costs Split Methods

The utility must categorize distribution plant data separately into demand- and customer-related costs when installing a distribution plant to provide service to a customer and fulfill the specific customer's peak demand requirements. The demand and customer components of distribution facilities are calculated using two different methodologies. They are the minimum-intercept-cost (or zero-intercept-cost, if appropriate) of facilities and the minimum-size-of-facilities approach.

The Minimum-Size Method
A minimal-size distribution system can be developed to meet the customer's minimum loading requirements, which is a precondition for classifying a distribution plant using this classification approach. The minimum-size method entails identifying the minimum size of the utility's installed pole, conductor, cable, transformer, and service. The average book cost of each piece of equipment typically dictates the cost of all installed units. The minimal size distribution system is thereafter computed for each primary plant account and categorized as customer-related expenditures. For each account, the demand-related costs are the sum of the entire account investment and the customer-related costs.

The Minimum-Intercept Method
The minimum-intercept method aims to pinpoint the area of the plant that would be affected by a fictitious no-load or zero-intercept scenario. In comparison to the minimum-size approach, this calls for a lot more information and computation. The method involves creating a curve for different sizes of the equipment involved using regression techniques, extending the curve to a no-load intercept, and relating installed cost to current carrying capacity or demand rating. The customer component is the cost associated with the zero-intercept.

1.5.9 Criteria for the Selection of Appropriate Allocation Method

Before switching to the process of selection allocation method, the following criteria should be considered:

- Allocators should consider a cause-and-effect relationship when possible
- Cost allocations between services must follow a mutually consistent pattern
- Cost allocations must be able to be reconciled with the overall cost being allocated
- Cost allocators must be realistic
- Allocators could alter with time
- The consistency of specific allocators is less significant than the consistency and quality of the allocation aims and results
- There is no requirement that causal allocations of cost be continuous or directly proportional to units of service output

- An allocator's quantum cannot be fixed or prescribed throughout several periods[36]

The most suitable strategy and the proper choice of a comprehensive allocation approach may be influenced by various factors, including:

- Utility's loads state (increasing, decreasing, or staying the same)
- Availability of a variety of supply resources to accommodate a range of load levels
- Dependence on transmission infrastructure
- The way in which supply is mainly distributed
- Usage by utility of renewable resources that are subject to change, such wind and solar power
- The way in which utility customers are divided into groups and subgroups with distinctly different cost characteristics;
- Availability of an accurate hourly load data broken down by class
- Availability of resources for demand response that can assist it meet high peak demand
- Ability of the utility to move generation or loads between time periods using its storage resources
- Period or season when the peak load for the utility occurs

Answers to these questions have an impact on the best cost allocation strategy. A method that properly classifies and allocates a variety of resources differently is necessary when there is a mix of resources. A system that allocates variable resources' costs to the hours during which they generate benefits is necessary.

1.6 Attributing Customer costs by Allocation

1.6.1 Definition of the Rate Class

Customer classes are the various categories of customers who are grouped together under each rate schedule based on shared characteristics and are charged identically for their electricity use. A customer class is typically made up of a group of customers who share similar characteristics, such as delivery voltage, energy consumed, load and end-use characteristics, conditions and types of metering, and conditions of service and geography.[37] Main types of customer classes are residential customers, commercial customers, industrial customers, and street lightning customers. This section is an overview of residential, commercial, and industrial customer classes.

1.6.1.1 Residential

Residential customers are customers metered at low voltage supply single phase. Space heating and cooling (air conditioning), lighting, water heating, space heating, and appliances and electronics are the most common single uses of electricity in the residential sector. Some utilities categorize residential customers based on size, such as peak demand or energy consumption. This can be significant in jurisdictions that formally classify farms or large master-metered multi-family buildings as residential. Some jurisdictions also distinguish between classes based on the use of specific technologies, such as electric resistance heating. Low-income discount customers are treated as a separate rate class in some jurisdictions.

Cost is usually used to justify the creation of multiple residential classes or subclasses. Many cost distinctions exist between different types of residential customers, and simple postage stamp cost allocation and rate structures may not capture many of those distinctions. Some distinctions are based on technology (i.e., on the load impacts of certain technologies, such as electric space heating, electric

[36] "KPMG Telstra FLSM Report." KPMG. 2014, https://www.accc.gov.au/system/files/KPMG%20July%20Report%20%28public%20version%29.pdf
[37] "Primer on Rate Design for Cost-Reflective Tariffs." USAID & NARUC.

water heating, solar or other distributed generation, and even electric vehicles). For example, electric space heating customers are more likely than non-heating customers to have different load characteristics, with significantly more consumption and a different daily load shape in the winter.

In the case of a winter-peaking system, this could imply that electric heating customers should bear a higher proportion of the costs. Electric heating customers, on the other hand, should be allocated proportionately lower overall costs in a summer-peaking system. This issue, which is essentially a question of potential intraclass cross-subsidization between types of residential customers, can, however, be addressed through rate design changes. Seasonally differentiated rates, when properly based on cost causation, can achieve the same distributional impact as separate rate classes for heating and non-heating customers while providing additional benefits from improved pricing efficiency.

Other distinctions are based on the characteristics of service. Those with relatively large impacts on cost allocation include:

- Single family versus multi-family
- Urban (multiple customers per transformer) versus rural (one customer per transformer)
- Overhead service versus underground service

For instance, some utilities establish distinct rate classes for single-family and multi-family residential customers based on rationale that the average cost of serving multi-family buildings is significantly lower than the cost of serving single-family homes due to shared service drops, more efficient sizing, lower distribution cost per customer, cost savings from manual meter reading, etc.

In some service territories, there may be countervailing considerations, such as if multi-family buildings are served by more expensive underground service and single-family buildings are served by less expensive overhead lines. A similar set of considerations may lead some utilities to divide customers up geographically, such as those who live within and outside city limits. Customers in remote areas are more expensive to serve because they are typically too far away.[38]

1.6.1.2 Commercial

The commercial and industrial classes are frequently referred to as general service rate classes. Voltage levels are frequently used to categorize general service customers. Customers served at primary distribution voltage do not use secondary distribution facilities and should not be charged for them, and customers served at transmission voltage do not use distribution facilities and should not be charged for them. Many utilities also divide general service classes with greater granularity than simple voltage criteria allow.[39]

Commercial customers are frequently divided into small and large commercial customers based on their load. The commercial sector includes government facilities, service-providing facilities and equipment, and other public and private organizations. Lighting and heating, ventilation, and air conditioning are the most common single uses of electricity in the commercial sector. Electricity demand in the commercial sector is highest during operating business hours and drops significantly at night and on weekends. Residential and small-business customers have higher total costs per kWh of usage because they require more distribution investment and have usage concentrated during peak times of the day and year. Because they require fewer distribution facilities and have more consistent usage patterns, industrial customers have lower total costs per kWh.[40]

[38] Lazar, J., Chernick, P., Marcus, W., and LeBel, M. "Electric cost allocation for a new era: A manual" Regulatory Assistance Project (RAP).
[39] Ibid.
[40] "Electricity Regulation in the US: A Guide." Regulatory Assistance Project (RAP).

1.6.1.3 Industrial

Industrial customers are medium- and large-scale businesses that require higher voltages and a maximum demand that exceeds a minimum amperage. Electricity is used by industrial customers' facilities and equipment to process, produce, or assemble goods in industries as diverse as manufacturing, mining, agriculture, and construction. Powering various motors, heating, cooling, and electro-chemical processes in which electricity is used to cause a chemical transformation (for example, the processes that produce aluminum metal and chlorine) are all significant applications. Electricity consumption in the industrial sector does not vary as much as it does in the residential and commercial sectors, particularly in manufacturing facilities that operate around the clock.

1.6.2 Cost-causation

1.6.2.1 Allocation of Costs (to a Certain Customer Cost of "Dedicated Facilities")

In order to allocate costs among customer classes, the customers served by the utility are separated into several groups based on the nature of the service provided and load characteristics. As stated earlier, the three principal customer classes are residential, commercial, and industrial. It may be reasonable to subdivide the three classes based on characteristics such as size of load, the voltage level at which the customer is served, and other service characteristics such as whether a residential customer is all-electric or not. Additional customer classes that may be established are street lighting, municipal, and agricultural.[41]

The objective is to allocate costs to the respective customer category in relation to the cost impact imposed by the consumer category on the power system. Allocation of costs to specific customer classes is based on the customer's contribution to the specific classifier selected. For instance, demand-related costs are allocated to a customer group using that customer group's contribution to the particular measurement of system demand, whether CP peak, NCP, or some variation determined to be appropriate for the particular cost item. An analysis of customer requirement, loads, and usage characteristics is completed to develop allocation factors reflecting each of the classifiers. The analysis may include an evaluation of the system design and operations, its accounting and physical asset records, customer load data, and special studies.[42]

Some costs can be directly assigned to certain customer classes without being classified as demand-, energy-, or customer-related. These are generally costs associated with specific services, such as dedicated capital facilities, or with specific customer classes, such as lighting customers. According to direct assignment method, a small but in some cases important portion of costs can be directly assigned to a specific customer of a particular customer class because these costs can be exclusively identified as providing service to a particular customer. Examples of costs that are directly assigned include: customer-dedicated transmission radial lines or dedicated distribution substations; and street lighting facility costs.[43]

1.6.2.2 Application of Cost Drivers for a Fair Allocation

Effective cost allocation and rate design require the identification of central cost causation factors, or cost drivers. During these processes, it is crucial 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 different customer classes. The cost allocation process, by its nature, approximates cost responsibility and is not a tool of exceedingly precise measurements. One key underlying reality is that customers use electricity at different times, leading to the concept of load diversity. Load

[41] "Electric Utility Cost Allocation Manual." NARUC.
[42] "OPALCO's Cost of Service Analysis and Rate Design Process." OPALCO.
[43] "Class Cost of Service Study and Selected Rate Design." XcelEnergy.

diversity means the shared portions of the system need to be sized to meet only the CP loads for combined customer usage at each point of the system, rather than the sum of the customers' NCP loads. 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 crucial 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 COSS assume that these notionally fixed costs cannot be driven by energy use. However, this assumption may be incorrect. Utilities make investments and commit to "fixed" expenses for many reasons: to meet peak demands, reduce fuel costs, reduce energy losses, access lower-cost energy resources, and expand the system to attract additional business.

1.7 Developing and Analyzing COSS

1.7.1 Overview of the Rate-making Process

This section provides an overview of the rate-making process, which is divided into three phases. The first phase of the rate-making process is to determine the revenue requirement (i.e., required level of annual revenue). The second phase divides the revenue requirement among customer classes, with additional distinctions made between customer-related costs, demand-related costs, and energy-related costs. The final phase aims to set tariffs or rates designed to collect the assigned level of revenue from each class.

1.7.1.1 Determination of Revenue Requirement

Revenue requirement is the total amount of revenue required by a utility over a rate period to cover costs of services and earn reasonable rate of return.[44] The revenue requirement phase of a conventional rate case consists of calculating the utility's annual allowed regulatory asset base, allowed rate of return, and allowed operating expenses.

Identifying revenue requirement is a critical step in the rate-making process because underestimating a utility's revenue requirement makes recovering costs nearly impossible, regardless of how the tariff is structured. Overestimation of the revenue requirement, on the other hand, will result in consumers being overcharged for electric service and the utility earning more than its authorized return on capital.[45]

[44] "Distributed Solar Utility Tariff and Revenue Impact Analysis: A Guidebook for International Practitioners." NREL. 2020. https://www.nrel.gov/docs/fy21osti/78058.pdf
[45] "Primer on Rate Design for Cost-Reflective Tariffs." USAID & NARUC.

1.7.1.2 Allocation of Costs Among Customer Classes

In the second phase of rate-making process, the revenue requirement is allocated across customer classes in accordance with cost-based and policy priorities, determining the portion of the revenue requirement that is expected to be recovered from each customer class. Customer classes significantly varies among utilities, but typical classes for each utility usually include residential customers, small commercial customers, large commercial customers and industrial customers, irrigation and pumping, and street lightning customers.

During the cost allocation phase, the utility will assign costs to each customer class based on the various types of data: energy usage over specific time periods, various measures of demand, the number of customers in each class, and information on generation patterns.

The main difference between the COSS lies within the structure of revenue requirement. Revenue determination based solely on the marginal cost basis is typically greater or less than the allowed revenue requirement, which is typically computed on an embedded cost basis. As a result, the results of a marginal COSS must be reconciled in order to meet the annual revenue requirement. In addition to embedded and marginal cost studies results, other factors such as continuous rate changes, policy considerations as anticipated changes, and economic conditions in the service territory also influence cost allocation for each rate case. The final cost allocation among rate classes, as well as any other relevant data and analysis, is then used in rate design process.[46]

1.7.1.3 Rate Design

The COSS provides a starting point for designing rates rather than a precise and inflexible set of rates for each customer class. The COSS rates must then be adjusted for other factors such as social and economic concerns (e.g., size of customer bills, potential rate shock, who should pay for programs, environmental considerations). This entire procedure is known as rate design.[47] Rate design should always prioritize forward-looking efficiency, including concepts such as long-run marginal costs for the energy system and societal impacts in general, because rate design influences consumer behavior, which influences future costs. Rate design decisions also consider principles concerning clarity and the ability of customers to manage their bills and respond to price signals in rates.

1.7.1.4 Relationship Between Cost Allocation and Rate Design

Cost allocation is about ensuring equity among customer classes by providing an analytical foundation for allocating revenue requirements to various customer classes on a system. This can be done solely based on an analytical COSS or, more commonly, based on quantitative COSS and additionally considering gradualism, economic impacts on the service territory, and attention to changes in future costs.

Rate design, on the other hand, has a distinct set of objectives. Rates must be sufficient to allow the utility to recover determined revenue requirement and ensure equity among customers within a class and providing customers with understandable incentives to make efficient consumption decisions that affect future long-term costs. A regulator is likely to use both a backward-looking embedded cost allocation method and a forward-looking rate design approach that considers cost dynamics. Public policy objectives, such as environmental and public health requirements, can also be incorporated into rate design.

Separate rate tariffs allow specific customer groups to control their bills and manage their consumption behavior, whereas the COSS provides guidance on cost allocation among customer classes. Cost

[46] Lazar, J., Chernick, P., Marcus, W., and LeBel, M. "Electric cost allocation for a new era: A manual." Regulatory Assistance Project (RAP).
[47] "Electric Utility Cost of Service and Rate Design.' NARUC.

allocation class definitions usually considers large groups of customers with similar service characteristics. Smaller groups of customers with similar consumption characteristics, or even individual customers, are frequently considered in rate design.

1.7.2 Importance of Accurate Metering and Data for COSS

In the past, customer meters were used solely to measure usage and render bills. Today, so-called smart meters are part of a complex web of assets that enable energy efficiency, peak load management and improved system reliability, in addition to the traditional measuring of usage and rendering of bills. More recently, several utilities have used advanced meters to support demand response and other programs. Smart meters (along with supporting data acquisition and data management hardware and software) can provide several services that improve reliability and reduce costs of generation, transmission, and distribution. Potential benefits of smart metering system include:

- Reduced line losses
- Voltage control
- Improved system planning and transformer sizing
- The ability to implement rate designs that encourage energy efficiency
- Reduced peak loads
- Integration of electric vehicles and renewables

Operating savings are, among other things, reduced labor needs and improved outage management. Lastly, smart meters, distribution sensors, and modern computing power provide utilities with substantial amounts of data that can be used to determine the usage patterns of distribution and transmission equipment in detail and support direct hourly allocation of costs.

1.7.3 Process of Analyzing COSS

Essentially, cost allocation is about equity among customer classes (i.e., providing an analytical basis for assigning the revenue requirement to the various classes of customers on a system). This may be done strictly based on an analytical COSS or, more often, using quantitative COSS as a starting point, with wider considerations including gradualism, economic impacts on the service territory, and attention to changes anticipated in future costs. It is often the case that the information developed in the process of cost allocation is relevant to important issues in rate design. In most countries, embedded COSS are used to allocate costs among customer classes, but regulators consider long-run marginal costs, either implicitly or explicitly, in designing rates within classes.

The mix of embedded cost principles for cost allocation and marginal cost principles for rate design reflects a sense of balance between the notions of equity of overall cost allocation between classes and efficiency of rates applied within classes. In the United States, in states where the embedded COSS does not contain any time differentiation of generation, transmission, or distribution costs, regulators have adopted time-varying retail rates for many classes of customers to encourage behavior expected to reflect forward-looking and avoidable costs.

Although marginal COSS generally differentiate between time periods, even these studies provide limited guidance for rate design. The reason is that the factors that affect utility system design and construction may not be understandable to consumers. Hence, rates should be simple, understandable, and free from confusion as to calculation and application.

1.7.4 Ways to Implement Cost-Reflective Rates for all Customer Classes

From an economic perspective, the main rationale offered for the introduction of cost-reflective tariffs is that they better reflect the actual costs of generating, supplying, and transporting electricity to end users. According to the Australian Energy Market Commission, this means that consumers can more accurately value, and thereby efficiently respond to ways to help minimize these costs over time. This in turn will ensure energy expenditure is as low as efficiently possible for all consumers in the long run. Cost-reflective tariffs are seen to provide a financial incentive or 'price signal' that might encourage consumers to shift their energy-usage behavior in ways that improve network efficiency (e.g., by reducing their consumption during times of peak demand [when costs are higher] and/or shifting consumption to off-peak periods [when costs are lower]).[48]

In Nordic countries, the objective stated in national laws is to have objective and non-discriminatory tariffs, which means that they should be cost-reflective and not discriminate between customer groups.[49] Historically, the distribution system operators have focused on making the tariff design simple and understandable rather than fully cost-reflective for customers on lower voltage levels (e.g., household customers). For these customers, tariffs are mostly volumetric, which means that the tariff will vary depending on how much energy a customer consumes. A typical household customer pays a combination of a fixed and a volumetric tariff. For larger customers, a power-based component in the tariff has been more common.

The development of cost-reflective tariffs serves no purpose on its own if no customers adjust their behavior to use the grid in a more efficient manner. The marginal cost of using electricity increases the closer the electricity consumption comes to the maximum capacity in the network due to exponentially increasing network losses. An efficient energy-based component should thus send the price signal that it is more expensive to use electricity at a high load in the networks, since this is most cost-reflective due to the higher network losses and the higher risk of subscriptions to overlying networks being exceeded when close to maximum capacity.

According to economic theory, cost-reflective distribution tariffs should combine a short-term marginal energy-based component, a fixed component to recover the residual costs, and a forward-looking component based on a forward-looking cost model if capacity is scarce. Tariff design should reflect that electricity networks have high fixed costs and low variable costs in the short term. This is called the cost reflectivity principle. The methodology for calculating tariffs should be transparent and accessible to all stakeholders.

If the tariffs are cost-reflective and consumer-related principles are followed, the goal of a more efficient network utilization is manageable to obtain. More efficient network utilization can lead to lower costs in the long run for customers, since the grid is used in a more flexible way, wherefore investments in the grid can be avoided or postponed.

Changing the tariff design affects cost allocation (i.e., how costs should be covered and by which customer groups). Implementing more cost-reflective tariffs will not necessarily change the total bill for an average electricity customer in the short term. However, over time the changes in the tariff design will contribute to avoiding or postponing investments in the grid. This will lower the cost of the grid in the long term, implying that network costs will be lower than they would have otherwise been. Therefore, one could say that more cost-reflective tariffs in the long term are beneficial for the regular electricity grid customer since the tariff design might save costs for the distribution system operators and thereby the customers.

The effect of more cost-reflective tariffs might overall be beneficial for very price elastic customers and unfavorable for very price inelastic customers, ceteris paribus. For example, one can assume that a family with children living in an apartment will be more time restricted regarding cooking and washing and other electronic devices, than a single person living in a house, who can more easily change their consumption pattern. One could also imagine that some small industries might have an easier task of

[48] "Australian Consumers' Likely Response to Cost-Reflective Electricity Pricing." CSIRO. 2015. https://publications.csiro.au/rpr/download?pid=csiro:EP152667&dsid=DS2

[49] "Electricity distribution tariffs." NordREG. 2021, https://www.nordicenergyregulators.org/wp-content/uploads/2021/05/20210216-NR-WG-Tariff-report.pdf

moving their consumption than other small industries. Whether this is fair or not is a political question to raise, but it does not change the fact that economically speaking the price of using 1 kWh in the grid should still be as cost-reflective as possible.

1.7.5 How to Improve Long-Term Cashflow Stability Using Power Purchase Agreements – an Analysis of the Long-Term Impact of Power Purchase Agreements on Generation and End-User Rates

The power purchase agreement (PPA) is the agreement that serves as the foundation for the power project. It connects the power producer (project company) and buyer (offtaker) and facilitates investment in the power company by sponsors, developers, and lenders by establishing a consistent revenue stream over the life of the project. The PPA negotiates and specifies the project company's and offtaker's core obligations. The project company is typically responsible for arranging project investment and financing and then leveraging that financing to construct, operate, and maintain the asset during the PPA term. The offtaker is typically required to pay the project company for the capacity, availability, and/or power delivered by the project.

Aside from these obligations, the PPA will outline the parties' agreement on how to test the power plant, resolve disputes, and deal with major events such as force majeure and termination.[50] A PPA enables the customer to receive stable and often low-cost electricity with no upfront cost, while also allowing the system owner to benefit from tax credits and earn income from the sale of electricity. PPAs are mostly used for renewable energy systems, but they can also be used for other energy technologies like combined heat and power.[51]

PPAs are usually used for power projects when:

- If projected revenues of the project are uncertain, the PPA can be used to guarantee the volume of energy purchased and price paid required to make the project viable.
- There is a possibility of competition from cheaper or subsidized domestic or international competition, and the PPA can provide some certainty of being protected from such competition.
- Most of the product will be purchased by one or a few major customers. A government utility, for example, may purchase power generated by a power plant. The project company will get revenue certainty, and the purchaser will get supply security.[52]

A PPA can also be used by the utility if it wants to reduce energy costs, hedge against rising energy prices, or improve operational resiliency without investing its own money and wants a third party to own, install, and maintain an energy system. The PPAs can also be used when a utility is unable to directly benefit from renewable energy tax incentives or is located in a state or jurisdiction where third-party ownership of generation equipment is permitted.

The advantages and disadvantages of PPAs are:

Advantages	Disadvantages
• *Positive cash flows.* PPAs can cover 100% of project costs, and power purchased through the provider is typically less expensive than	• *Overpayment risk.* If retail electricity prices decline or increase more slowly than the escalator, the annual price escalation under a

[50] "Understanding Power Purchase Agreements – Second Edition." Commercial Law Development Program. https://cldp.doc.gov/sites/default/files/PPA%20Second%20Edition%20Update.pdf
[51] Better buildings, U.S. Department of Energy official site, https://betterbuildingssolutioncenter.energy.gov/financing-navigator/option/power-purchase-agreement
[52] "Power Purchase Agreements (PPAs) and Energy Purchase Agreements (EPAs)." The World Bank. 2021. https://ppp.worldbank.org/public-private-partnership/sector/energy/energy-power-agreements/power-purchase-agreements

the retail rate for electricity. This frequently results in the PPA cash flow being positive for the customer from day one; • *Third-party ownership and management.* A PPA allows the customer to avoid the risks and complexities of equipment ownership by having a third party install, own, and maintain the energy system; • *Off balance sheet.* A PPA is intended to be an off-balance-sheet financing solution, with regular payments treated as an operating expense in the same way that a standard utility bill is; • *Predictable energy prices and lower end user rates.* PPAs lock in agreed-upon energy prices and protect customers from utility rate fluctuations over time. Customers receive stable and often low-cost electricity with no upfront cost under the PPAs.	PPA (usually 1-5%) may result in the customer paying a rate higher than the market rate; • *Limited availability.* The laws governing PPAs differ from state to state. Some states have laws that make PPAs more difficult to use or outright prohibit them; • *Complexity of contracts.* PPAs can have more complicated contracts and higher transaction costs than outright purchasing a system. [53]

1.7.6 Recommended Approach for Kazakhstan and Uzbekistan

Regarding the current legislation on regulatory accounting, the Decree "On Approval of the Rules for the Formation of Tariffs" of the Minister of National Economy of the Republic of Kazakhstan dated November 19, 2019, No. 90 provides the list of costs that are allowed to be included in the tariffs and the list of costs that cannot be included in the tariffs, specifies the depreciation methods applied for different tariff methodologies, and includes the templates to be used.

In terms of cost allocation, the Decree states that each regulated subject has to allocate revenues, expenditures, and employed assets between each regulated service and other, nonregulated services. It also establishes the requirement to keep separate records for costs, provides basic principles of cost allocation, and includes templates to be used for each type of regulated service. However, the Decree does not provide details of cost classification and allocation stages, the recommended allocation bases, and its calculation approach for regulated companies in the electricity sector.[54] It is important to note that the power market in Kazakhstan is unbundled and responsibilities for electricity generation, transmission, and distribution are allocated to distinct entities/regulated companies in electricity sector, which operate independently.

Until 2019, the electricity system of Uzbekistan operated as a vertically integrated state-owned company, Uzbekenergo, responsible for the entire operation of the electricity system, including generation, transmission, distribution, and supply of electricity to consumers. In accordance with the Decree of the President of the Republic of Uzbekistan "On the strategy for the further development and reform of the electric power industry of the Republic of Uzbekistan" dated March 27, 2019, No. PP-4249, the electric power sector of Uzbekistan was divided into three parts: generation, transmission, and distribution.[55]

[53] Better buildings, U.S. Department of Energy official site, https://betterbuildingssolutioncenter.energy.gov/financing-navigator/option/power-purchase-agreement

[54] "Technical Assistance to Review Kazakhstan's tariff setting methodology and compare with best practices." USAID and NARUC. 2021.

[55] Decree of the President of the Republic of Uzbekistan "On the strategy for the further development and reform of the electric power industry of the Republic of Uzbekistan" dated March 27, 2019, No. PP-4249. ПП-4249-сон 27.03.2019. О стратегии дальнейшего развития и реформирования электроэнергетической отрасли Республики Узбекистан (lex.uz)

In Uzbekistan, starting from January 2021, tariffs for the generation, distribution, and transmission of electricity are approved based on the Decree of the Cabinet of Ministers of the Republic of Uzbekistan "On measures to further improve the tariff policy in the electric power industry" No. 310 dated April 13, 2019, using the "costs plus" approach. The current tariff methodology does not provide any incentives for regulated companies in terms of optimizing costs and consumption for their own needs. At the same time, the tariff for the end consumer is formed by summing up the weighted average costs for the production, transmission, distribution, and supply of electricity.[56]

This Decree establishes the fundamental principles and requirements for cost records and cost allocation and a general description of cost allocation approach (i.e., functionalization, cost classification, allocation stages), but does not go into detail about recommended allocation bases or the calculation approach for regulated companies in the electricity sector.

In this regard, regulatory authorities in Kazakhstan and Uzbekistan are encouraged to consider implementing COSS in the rate design process to analyze and allocate costs. More detailed cost allocation methodology/rules would provide an analytical basis for assigning the revenue requirement to the various classes of customers in a system and ensure equity among customer classes. At the initial stage in choosing a cost allocation method, regulatory authorities would determine the objective of the study. That is, whether it is centered on short-run equity considerations or on efficiency considerations. Thus, based on the objective, they could implement appropriate approaches.

The following are the main points that regulators should consider when choosing the most appropriate method. Most advocates of using embedded cost studies point to the direct link with the revenue requirement and spreading that revenue requirement among multiple customers. Although there is a wide range of embedded cost methods, all of them apportion the existing revenue requirement, and rates based on the results should produce the allowed amount of total revenue.

Long-run efficiency is another objective of cost allocation, which guides consumer consumption based on where costs are going rather than where they are. The use of long-run marginal costs attempts to do this in the cost allocation phase of rate-making. However, marginal costs are different from current costs that comprise the revenue requirement, so some method is required to reconcile (up or down) the results of a marginal cost study with the revenue requirement.

It is often the case that the information developed in the process of cost allocation is relevant to important issues in rate design. Rates must be sufficient to provide the utility with an opportunity to recover the authorized revenue requirement, but rate design is also about equity among customers within a class and about understandable incentives for customers to make efficient decisions about their consumption that will affect future long-term costs. It is common for a regulator to use a backward-looking embedded cost allocation method and a forward-looking rate design approach that considers where cost trajectories will go. Rate design can also incorporate public policy objectives, including environmental and public health requirements.

The mix of embedded cost principles for cost allocation and marginal cost principles for rate design reflects a sense of balance between the notions of equity of overall cost allocation between classes and efficiency of rates applied within classes. To conclude, the appropriate method for each utility may be slightly different. It is driven by the mix of customers, the nature of the service territory, the type of resources employed, and the underlying history that guided the evolution of the system. No single method is appropriate for every utility, and no single method is likely to produce a noncontroversial result.

[56] "In-depth review of the policy of the Republic of Uzbekistan in the field of energy efficiency." International Energy Charter. 2022.

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