Table 32. Summary of distribution allocation approaches

Element	Method	Comments	Hourly allocation
Substations	FUNCTIONALIZATION: Entirely primary CLASSIFICATION: Demand and energy ALLOCATOR: Loads on substations in hours at or near peaks	Reflect effect of energy near peak and preceding peak on sizing and aging	Allocate by substation cost or capacity, then to hours that stress that substation with peak and heating
Poles	FUNCTIONALIZATION: Entirely primary CLASSIFICATION: Demand and energy* ENERGY ALLOCATOR: Energy or revenue DEMAND ALLOCATOR: Loads in hours at or near peaks	Pole costs driven by revenue expectation	As primary lines
Primary conductors	FUNCTIONALIZATION: Entirely primary CLASSIFICATION: Demand and energy* ENERGY ALLOCATOR: Energy or revenue DEMAND ALLOCATOR: Loads in hours at or near peaks	• Distribution network is installed due to revenue potential • Sizing determined by loads in and near peak hours	• Cost associated with revenue-driven line extension to all hours • Cost associated with peak loads and overloads on distribution of line peaks and high-load hours
Line transformers	FUNCTIONALIZATION: Entirely secondary CLASSIFICATION: Demand and energy* ENERGY ALLOCATOR: Secondary energy DEMAND ALLOCATOR: Diversified secondary loads in peak and near-peak hours	Reflect diversity	Distribution of transformer peaks and high-load hours
Secondary conductors	FUNCTIONALIZATION: Entirely secondary CLASSIFICATION: Demand and energy* ENERGY ALLOCATOR: Energy or revenue DEMAND ALLOCATOR: Loads in hours at or near peaks	Energy is more important for underground than overhead	Distribution of line peaks and high-load hours
Meters	FUNCTIONALIZATION: Advanced metering infrastructure to generation, transmission and distribution, as well as metering ALLOCATOR FOR CUSTOMER-RELATED COSTS: Weighted customer	Allocation of generation, transmission and distribution components depends on use of advanced metering infrastructure	N/A

* Except some to customer, where a significant portion of plant serves only one customer

costs due to load shifting and line loss reduction. Legacy methods for allocating metering costs as primarily customer-related would place the vast majority of these costs onto the residential rate class, but many of the benefits are typically shared across all rate classes. In other words, the legacy method would give commercial and industrial rate classes substantial benefits but none of the costs.

Table 31 identifies some of the key elements of smart grid cost and how these would be appropriately treated in an embedded cost of service study. These approaches match smart grid cost savings to the enabling expenditures.

11.6 Summary of Distribution Classification and Allocation Methods and Illustrative Examples

The preceding discussion identifies a variety of methods used to functionalize, classify and allocate distribution plant. Table 32 summarizes the application of some of those methods, including the hourly allocations that may be applicable for modern distribution systems with:

- A mix of centralized and distributed resources, conventional and renewable, as well as storage.
- The ability to measure hourly usage on the substations and feeders.
- The ability to estimate hourly load patterns on transformers and secondary lines.

Table 33. Illustrative allocation of distribution substation costs by different methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Class NCP: substation (legacy)	$9,730,000	$9,730,000	$7,297,000	$3,243,000	$30,000,000
Average and peak	$10,056,000	$10,056,000	$8,100,000	$1,788,000	$30,000,000
Hourly	$9,939,000	$10,533,000	$9,009,000	$519,000	$30,000,000

Note: Numbers may not add up to total because of rounding.

Where the available data or analytical resources will not support more sophisticated analyses of distribution cost causation, the following simple rules of thumb may be helpful.

- The only costs that should be classified as customer-related are those specific to individual customers:
  - Basic metering costs, not including the additional costs of advanced meters incurred for system benefits.
  - Service lines, adjusting for shared services in buildings with multiple tenants.
  - For very rural systems, where most transformers and large stretches of primary line serve only a single customer (and those costs are not recovered from contributions in aid of construction), a portion of transformer and primary costs.
- Other costs should be classified as a mix of energy and demand, such as using the average-and-peak allocator.
- The peak demand allocation factor should reflect the distribution of hours in which various portions of distribution system equipment experience peak or heavy loads. If the utility has data only on the time of substation peaks, the load-weighted peaks can be used to distribute the demand-related distribution costs to hours and hence to classes.

11.6.1 Illustrative Methods and Results

The following discussion and tables show illustrative methods and results for several of the key distribution accounts, focused only on the capital costs. The same principles should be applied to O&M costs and depreciation expense. These examples use inputs from tables 5, 6, 7 and 27.

Substations

Table 33 shows three methods for allocating costs of distribution substations. The first of these is a legacy method, relying solely on the class NCP at the substation level.[169] The second is an average-and-peak method, a weighted average between class NCP and energy usage. The third uses the hourly composite allocator, which includes higher costs for hours in which substations are highly loaded.

Primary Circuits

Distribution circuits are built where there is an expectation of significant electricity usage and must be sized to meet peak demands, including the peak hour and other high-load hours that contribute to heating of the relevant elements of the system. Table 34 on the next page illustrates the effect of four alternative methods. The first, based on the class NCP at the circuit level, again produces unreasonable results for the street lighting class. The second, the legacy minimum system method, is not recommended, as discussed above. The third and fourth use a simple (average-and-peak) and more sophisticated (hourly) approach to assigning costs based on how much each class uses the lines and how that usage correlates with high-load hours.

Transformers

Line transformers are needed to serve all secondary voltage customers, typically all residential, small general

169 The street lighting class NCP occurs in the night, and street lighting is a small portion of load on any substation, so the street lighting class NCP load rarely contributes to the sizing of summer-peaking substations. The NCP method treats off-peak class loads as being as important as those that are on-peak. This is particularly inequitable for street lighting, which is nearly always a load caused by the presence of other customers who collectively justify the construction of a circuit.

Table 34. Illustrative allocation of primary distribution circuit costs by different methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Class NCP: circuit (legacy)	$69,565,000	$69,565,000	$43,478,000	$17,391,000	$200,000,000
Minimum system (legacy)	$113,783,000	$51,783,000	$24,739,000	$9,696,000	$200,000,000
Average and peak	$67,041,000	$67,041,000	$53,997,000	$11,921,000	$200,000,000
Hourly	$66,258,000	$70,221,000	$60,059,000	$3,462,000	$200,000,000

Note: Numbers may not add up to total because of rounding.

service and street lighting customers and often other customer classes as well. We present four methods in Table 35: two archaic and two more reflective of dynamic systems and more granular data. All of these apportion no cost to the primary voltage class, which does not use distribution transformers supplied by the utility.

The first method is to apportion transformers in proportion to the class sum of customer noncoincident peaks. This method is not recommended because it fails to recognize that there is great diversity between customers at the transformer level; as noted in Subsection 11.3.3, each transformer in an urban or suburban system may serve anywhere from five to more than 50 customers. The second is the minimum system method, also not recommended because it fails to recognize the drivers of circuit construction, as discussed in Section 11.2. The third is the weighted transformers allocation factor we derive in Section 5.3 (Table 7), weighting the number of transformers by class at 20% and the class sum of customer NCP (recognizing that the diversity is not perfect) at 80%. The last is an hourly energy method but excluding the primary voltage class of customers.

Customer-Related Costs

The final illustration shows two techniques for the apportionment of customer-related costs, based on a traditional customer count and a weighted customer count. Even for simple meters used solely for billing purposes, larger customers require different and more expensive meters. There are fewer of them per customer class, but the billing system programming costs do not vary by number of customers. In addition, a weighted customer account is also relevant to customer service, discussed in the next chapter, because the larger use customers typically have access to superior customer service through "key accounts" specialists who are trained for their needs.

Table 35. Illustrative allocation of distribution line transformer costs by different methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Customer NCP (legacy)	$32,258,000	$16,129,000	$0	$1,613,000	$50,000,000
Minimum system (legacy)	$32,461,000	$14,773,000	$0	$2,766,000	$50,000,000
Weighted transformers factor	$29,806,000	$14,903,000	$0	$5,290,000	$50,000,000
Hourly	$23,810,000	$23,810,000	$0	$2,381,000	$50,000,000

Note: Numbers may not add up to total because of rounding.

Table 36. Illustrative allocation of customer-related costs by different methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Unweighted					
Customer count	100,000	20,000	2,000	50,000	172,000
Customer factor	58%	12%	1%	29%	100%
Customer costs	$58,140,000	$11,628,000	$1,163,000	$29,070,000	$100,000,000
Weighted					
Weighting factor	1	3	20	0.05	
Customer count	100,000	60,000	40,000	2,500	202,500
Customer factor	49%	30%	20%	1%	100%
Customer costs	$49,383,000	$29,630,000	$19,753,000	$1,235,000	$100,000,000

Note: Numbers may not add up to total because of rounding.

Table 36 first shows a traditional calculation based on the actual number of customers. Then it shows an illustrative customer weighting and a simple allocation of customer-related costs based on that weighting. Each street light is treated as a tiny fraction of one customer; although there are tens of thousands of individual lights, the bills typically include hundreds or thousands of individual lights, billed to a city, homeowners association or other responsible party.[170]

170 In some locales, street lighting is treated as a franchise obligation of the utility and is not billed. In this situation, there are no customer service or billing and collection expenses.

12. Billing and Customer Service in Embedded Cost of Service Studies

Many utilities classify billing and customer service costs, often termed retail service costs, as almost entirely customer-related and allocate these costs across classes based on the number of customers. This chapter describes how these costs can be allocated in a more granular and detailed way.

12.1 Billing and Meter Reading

Most utilities bill customers either monthly or bimonthly. The reason for this is relatively simple: If billed less frequently, the bills would be very large and unmanageable for some consumers; if billed more frequently, the billing costs would be an unacceptable part of the total cost. As noted in Subsection 3.1.5, billing closer to the time of consumption provides customers with a better understanding of their usage patterns from month to month, which may assist them in increasing efficiency. There are exceptions: Many water, sewer and even electric utilities serving seasonal properties may render bills only once or twice a year.[171]

It is important to recognize these cost drivers in the classification of billing costs. From a cost causation perspective, the reason for frequent billing is that usage drives the size of the bill. We receive annual bills for magazine subscriptions because the quantity we will use (one per week or month) is very small and predictable. In some states, rules of the regulatory commission require billing on a specified interval. For example, in Washington state, the rules require billing not less than bimonthly (Washington Administrative Code Title 480, Chapter 100, § 178[1][a]). In this situation, billing frequency in excess of that required by law or regulation is driven by consumption. The portion of the costs of reading meters and billing more frequently should be classified and allocated according to appropriate measures of usage, rather than customer count.

Manual reading of the meters of large customers typically takes longer than for small customers, both because of travel distance among larger customers and the complexity of metering typical of large customers (TOU or demand-metered). In some cases, small customer meters are read manually but large customers are remotely metered; the additional costs of the equipment for that remote metering should be assigned to the classes that use remote metering. As noted in Section 11.5, unmetered customers such as streetlights should not be allocated meter reading costs.

For utilities with AMI, any meter reading costs arising from customers opting out of AMI should be recovered either from the opt-out customers or functionalized, classified and allocated in proportion to the AMI costs, because opt-outs are part of the cost of obtaining the benefits of AMI.

The costs of billing, payment processing and collections for special services (e.g., line extensions and relocations) can end up in Account 903 for some utilities. These are overhead costs, not customer costs, and should be either classified or allocated as an overhead expense.[172]

Some utilities provide on-bill financing for energy efficiency, renewable energy or demand response investments that the utility (or a third party) makes at the customer premises. Where this occurs, a portion of the billing cost should be assigned to the nonservice cost element.

12.2 Uncollectible Accounts Expenses

Uncollectible accounts expenses are the expenses from customers who have not paid their bills, due to financial

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

172 The same is true for any uncollectible charges for special services. If there is direct assignment of uncollectibles, charges related to non-energy billings or claims should be segregated from the remainder of Account 904 and directly assigned as overhead expenses.

distress, bankruptcy or departure from the service territory.[173] Some analyses erroneously allocate the costs of former customers to the classes of current customers on a per-customer basis or by direct assignment. However, these costs are not caused by any current customer in any particular class.[174] Although certain accounts have unpaid electric bills, those accounts are former customers who are no longer members of any class.

Uncollectible accounts are related to class revenue in two ways. First, the higher the bills of a particular class, the more revenue is at risk of becoming uncollectible. Second, if the customer had shut down or left before rates were set, most of the costs reflected in the uncollectible bills would have been allocated to the remaining customers, in all classes. Hence, uncollectible revenues should be classified as revenue-related and allocated in proportion to revenues, not customer number.[175]

The treatment of four elements should be coordinated in the cost of service study:

- Uncollectible accounts expenses.
- Late payment revenues if charged to all classes (sometimes called forfeited discounts, often recorded in FERC Account 450 in the Uniform System of Accounts).
- Customer deposits, which protect utilities against uncollectibles and which offset rate base for most utilities in North America.
- Interest paid to customers on customer deposits.

If uncollectible accounts expenses are assigned as an overhead expense based on revenue, then all of these four items should be allocated based on revenue.

On the other hand, if uncollectible accounts expenses are directly assigned to the originating class or using a customer allocator, then late payment revenues and customer deposits should be assigned in the same manner.

Although an allocation based on revenue is more appropriate, the consistent allocation of these four items by either revenue or direct assignment may not have a large effect on the cost of service study, because direct-assigned late payment revenues and deposits partly offset direct-assigned uncollectible accounts expenses.

The worst cost allocation outcome is inconsistency: assigning uncollectible accounts expenses largely to residential customers using direct assignment or a per-customer allocation while using a broad allocation method for late payment charges and customer deposits, even though both of these items are also largely paid by residential customers.

12.3 Customer Service and Assistance

Utilities frequently classify customer service and information expenses as customer-related and allocate them in proportion to customer number. This approach is not reasonable, because these expenses are more likely to vary with class energy consumption and revenues.

In general, larger customers have more complicated installations, metering and billing and warrant more time and attention from a utility. 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, considering the fact that the larger customers may have bills 100 or 1,000 times that of the average residential customer. Indeed, most utilities have key accounts specialists — highly trained customer service personnel who concentrate on the needs of the largest customers. Large customers may also have more complex billing arrangements, multiple delivery points, demand charges, campus billing, interruptible rates and credits, transformer ownership credits and additional complications that require more time from engineering, legal and rate staff, supervisors and higher management, so 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

173 For most utilities, the residential class produces most of the uncollectible accounts expenses, in part because large customers are more often required to post deposits or demonstrate good financial standing. However, when large customers' bills are uncollectible, often due to bankruptcy, the amounts can be very large.

174 Texas has one of the strongest precedents on this issue for utilities not in ERCOT and therefore not subject to competition. See Public Utility Commission of Texas (2018, p. 47, findings of fact 303-305).

175 Texas and California have treated these costs as overhead costs, allocated by revenue to all customer classes.

allocator — in which larger customers are assigned a multiple of the costs assigned to smaller customers — or a combination of customer number and class revenue. The retail allocators should be derived from the relative cost or effort required per customer for each class.

Most utilities can segregate costs for key accounts and identify the customer classes for which these services are provided. Although these costs should be recorded in customer service costs (accounts 907 to 910), they can appear in other accounts. Wherever they appear, they should be assigned to the classes that use them. The costs should be assigned mostly to the largest commercial and industrial customers who receive the services, perhaps with a small amount allocated to classes with smaller nonresidential customers.[176]

Account 908, which FERC identifies as customer assistance expenses, contains general advice and education on electrical safety and energy conservation. Account 909 involves informational advertising. Those activities are generally not extensive (or expensive), and allocation is not usually controversial. But many utilities also book to this account energy efficiency expenditures, which can represent a few percent of consumer bills. If there are significant costs in this account, they are likely to be dominated by energy efficiency programs, which should be allocated as described in Section 14.1.

12.4 Sales and Marketing

Sales and marketing costs are often erroneously allocated by the number of customers rather than the purpose of sales and marketing expenses: to increase electric loads (e.g., by economic development or load retention). 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 (such as energy efficiency or electric vehicles, discussed further in sections 14.1 and 7.1.3, respectively). Other sales and marketing efforts, however, may promote programs that ratepayers arguably should not fund at all (e.g., promotion of inefficient electric resistance heating by a utility that is almost entirely fossil fuel-based, through sponsorships and advertising) and should be examined closely in revenue requirements cases.

176 A few large customers billed on multiple small or medium commercial tariffs may receive key-customer services, such as franchisees, government agencies and small accounts attached to large ones.

13. Administrative and General Costs in Embedded Cost of Service Studies

Utilities have very significant administrative overhead costs, including general plant (office buildings, vehicles, computer systems), labor costs (executive compensation, employee benefits) and the cost of outside services. Some cost of service studies functionalize a portion of each category of general plant and overhead costs to each of the first four functions. Other cost of service studies treat overhead as a function and allocate those costs to classes in proportion to the costs allocated to other functions, or on such drivers as the labor cost incurred by each of the other functions.[177] In this regard, the structure of the cost of service does not constrain or distort the allocation of overhead costs.

Overheads are costs that cannot be directly assigned to particular functions. The overhead category includes the capital costs and depreciation expenses recorded as general plant in accounts 389 to 399 (which includes office buildings and warehouses), property taxes in Account 408, employment taxes in Account 408.2 and the O&M expenses recorded as administrative and general in accounts 920 to 935.

13.1 Operations and Maintenance Costs in Overhead Accounts

Some costs included as A&G expenses may be more accurately treated as O&M for specific functions. Utilities do not all interpret the FERC Uniform System of Accounts in the same way. For example, a utility may include some or all of its expenses for procuring electricity and fuel in Account 920 (administrative salaries) and Account 921 (office expenses). These costs should be treated as energy-related, either by being refunctionalized to fuel costs and Account 557 (other power supply expenses) or allocated in proportion to those costs or on energy. Similarly, some utilities include all or a portion of the major accounts expenses (discussed in Section 12.3) in accounts 920 and 921. These should be reclassified to customer service and assigned to the classes with the large customers who receive these services.

13.2 Labor-Related Overhead Costs

Some of the A&G accounts in the standard utility accounting systems serve a single function and are driven by a single factor. For example, 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 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.[178]

If the administrative overheads are available disaggregated by department or function, the human resources or personnel office should also be functionalized or allocated in proportion to labor. For administrative labor and other costs that cannot be directly functionalized, see Section 13.5.

13.3 Plant-Related Overhead

Accounts 924 (property insurance) and 925 (injuries and damages) are clearly plant-related and are generally functionalized or allocated in proportion to plant, with the exception of workers' compensation expenses in Account 925,

177 In setting wholesale transmission rates, FERC allocates A&G and general plant costs among jurisdictions by labor, with the exception of property insurance Account 924 (by plant) and regulatory commission expenses (directly assigned). As described in sections 5.2 and 5.3, this treatment is overgeneralized.

178 If nonfuel O&M is used instead of labor, transmission wheeling expenses, uncollectible accounts expenses and regulatory amortizations to operation and maintenance accounts should also be excluded, since these costs do not require supervision and administrative cost.

which are labor-related.[179] The same is true for property taxes that are based on the assessed value of each utility facility.[180] Typically, an allocator based on net plant (or net plant less deferred taxes) is used, but the allocation should reflect the method by which taxes are assessed in each state.

13.4 Regulatory Commission Expenses

The benefits to customers of the regulatory oversight funded through FERC Account 928 will normally be distributed more in proportion to the classes' total bills, including both investment-related costs and operating expenses, rather than to the number of customers in the classes. In terms of cost causation, the regulatory assessment covers expenditures on many types 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.[181]

13.5 Administrative and Executive Overhead

Many of the standard A&G accounts serve multiple functions. Administrative salaries pay employees in human resources, financing, public relations, regulatory affairs, the legal department, purchasing and senior management. Some of their work is driven by employee numbers (e.g., human resources), others by capital investment (finance) and most by a mix of labor, fuel procurement, nonfuel expenses and capital investments, including dealing with disputes with suppliers, customers, regulators and other parties. Outside purchased services may include consultants on new power plants, fuel and equipment procurement, power transactions, environmental compliance, worker safety and many other activities.

These costs are driven by the utility's entire operation, including labor, other O&M and plant investment. If these corporate overheads can be differentiated in sufficient detail (sections 13.1, 13.2 and 13.3), they can be functionalized or allocated to specific cost categories. Otherwise, these costs can be allocated in proportion to class revenue (or the total of other cost allocations).

Utilities agree to franchise payments (in Account 927) to gain access to customers and the associated revenues; thus franchise payments should be allocated in proportion to total revenues or other allocated costs.

13.6 Advertising and Donations

Some utilities assign Account 930.1 (general advertising) or certain donations as customer-related. This treatment is erroneous. General advertising is not trying to inform customers of anything they need to know about their regulated utility service (the purpose of Account 909) or sell them anything (Account 913). Rather Account 930.1 includes "cost of advertising activities on a local or national basis of a good will or institutional nature, which is primarily designed to improve the image of the utility or the industry" (18 C.F.R. § 367.901[d]). If allowed in rates at all, these costs are clearly overheads, even if the expenditures are largely intended to affect the opinions of residential customers (or voters). To the extent that some donations are allowed in rates (as in Texas), they also are image-building and charitable overhead and, as such, should not be assigned by the number of customers.

179 As a refinement, a study could be done to determine workers' compensation costs by functions. Customer service representatives (largely customer-related in Account 903) are likely to have lower workers' compensation costs than power plant operators or power line workers.

180 For publicly owned utilities, the equivalent may be payments in lieu of taxes.

181 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.

14. Other Resources and Public Policy Programs in Embedded Cost of Service Studies

14.1 Energy Efficiency Programs

Energy efficiency costs have three effects on the revenue requirement that will be recovered through rates. First, energy efficiency shrinks the size of the pie of non-energy efficiency costs that have to be split up, because the utility will need less generation, transmission and distribution in the long run, and utilities that own generation may be able to earn some export revenues to offset other costs. Since utilities generally undertake energy efficiency only if it is less expensive than the avoided costs (sometimes measured as short run, sometimes as long run, and including or excluding environmental costs), energy efficiency tends to reduce total costs, at least in the long term.

Energy efficiency programs typically reduce generation, transmission and distribution costs, and hence also some of the associated overheads, but not most retail service costs, such as metering and billing.[182] In restructured utilities, energy efficiency load reductions tend to reduce the prices that all customers pay for generation services, as well as avoiding transmission and distribution investments. These benefits typically are dominated by energy savings, with a portion being demand-related. Some utilities collect energy efficiency costs from all customers, on an equal cents-per-kWh basis or using an energy/demand allocator. Where this is done, the allocation of program costs should generally follow the framework for revenue collection.

Second, a program that reduces the loads of one class shrinks its share of the cost pie, increasing other classes' shares of the pie. For the participating class, the reduction in both the size of the pie and the class's share of the pie reduces customers' cost allocation. For each class participating in each program, the program reduces the bills of participants and the costs allocated to the class. Thus, some utilities have assigned the costs of each energy efficiency program to the participating classes. But for some other class, the increase in its share of the costs may be either larger or smaller than the effect on the size of the total pie, so its cost allocation may either rise or fall due to the energy efficiency.

Thus, cost-effective energy efficiency, with the costs allocated to classes based on the class share of the system benefits, can result in nonparticipating classes paying more than they would without energy efficiency. Conversely, assigning the costs directly to the participating class or classes can result in the participants paying more for energy efficiency programs than they benefit from the shrinking of the revenue requirements and of their share, leaving them worse off. These are extreme situations. With highly cost-effective programs and broad participation, all classes are very likely to benefit from energy efficiency, no matter how the costs are allocated. But the net benefits can be inequitably allocated.

The cost effects of energy efficiency differ between the short term and the long term. The costs of energy efficiency investment are often incurred in the year of program implementation, while the benefits stretch on for many years. In 2018, the customers will be paying roughly the costs of the 2018 program, while nonparticipating customers in 2018 are primarily receiving the benefits of energy efficiency investment that occurred in the past. This could be another source of misalignment between cost recovery and benefits, particularly if there are changes over time in the cost recovery method or the relative benefits to each customer class.

Energy efficiency costs are typically caused by the opportunity to reduce total costs to consumers. For most costs, revenue requirements would be lower if customers did less to require the utility to incur those costs. Customers

182 Energy efficiency programs targeted to low-income customers can reduce collection costs, uncollectibles and other burdens on the utility and other customers.

whose load growth requires upgrades to their service drops and transformers, extension of three-phase primary distribution and retention of more hydro energy that could have been exported would increase costs to the system. The same is true for customers who want their service drops underground for aesthetic reasons. Other customers should not bear those costs, so the costs are assigned or allocated to the participating class and billed (more or less) to the customer demanding the service. If customers do not want to pay the costs, they should not increase their load or request more expensive services.

The allocation of energy efficiency costs should reflect both the system benefits and the benefits to the participating classes, while avoiding making any class worse off.

Unlike other costs, energy efficiency costs produce benefits for the participating class and entire system. Utilities do not want to discourage participation in energy efficiency efforts, and they recognize there are benefits beyond the participant. In principle, the cost of service study might allocate all energy efficiency costs to the participating rate classes, offset by all the system benefits of energy efficiency. In practice, it would be difficult. The cost savings in 2020, for example, will result from expenditures made in earlier energy efficiency programs, and relatively little savings will be realized for nonparticipants in 2020 from the activities underway in that year. Determining the load reductions in 2020 from those prior years' programs, the cost savings from the load reductions and the class responsibility for those savings would be quite complex.

The allocation of energy efficiency costs should reflect both the system benefits from energy efficiency and the benefits to the participating classes, while avoiding making any class worse off. If a utility has high avoided costs and low embedded costs, the first solution may result in a class being charged for all the costs of the energy efficiency it undertakes, even though most of the benefit flows to other classes, leaving the participant class worse off than if it had not participated. That outcome would not be equitable and would not encourage the class to engage in further efficiency. If a utility has relatively low avoided costs and high embedded costs, the second option may result in the participating class's revenue requirements falling by more than the total net benefit of the energy efficiency program, leaving other classes with higher bills. That outcome would also be inequitable and may inspire each class to oppose energy efficiency proposals for the other classes.

The allocation of energy efficiency program costs should avoid both of these extremes, which may lead to the use of a split between energy-related and demand-related, direct assignment to participating classes or a combination of the two approaches (such as 50% of the costs being directly assigned and the rest allocated based on energy usage).

To avoid these problems, the utility could estimate the effects of recent or planned energy efficiency on revenue requirements for each class, for alternative allocations. This analysis would include the long-term annual revenue requirements for three cases:

1. Actual or planned energy efficiency spending and load reductions, with energy efficiency costs assigned to the participating classes and system revenue requirements allocated roughly as they would flow through the cost of service study.
2. Actual or planned energy efficiency spending and load reductions, with energy efficiency costs allocated in proportion to avoided costs (using weighted energy or other allocators reflecting the composition of avoided costs) or total revenues, and system revenue requirements allocated roughly as they would flow through the cost of service study.
3. No energy efficiency, resulting in higher loads, higher energy costs, lower export revenues and higher T&D costs.

The difference between case 1 and case 3 would show the effect on rate classes of assigning energy efficiency costs by class, and the difference between case 2 and case 3 would show the effect on rate classes of allocating energy efficiency costs in proportion to the system benefits. Based on that analysis, the cost of service study should use an allocation approach that is fair to all classes, avoiding a situation in which one class is paying for its own energy efficiency efforts that are disproportionately benefiting other classes or, conversely, paying for energy efficiency for other classes and receiving little of the benefit.

14.2 Demand Response Program and Equipment Costs

Demand response programs may avoid generation, transmission and distribution investments depending on the specifics of the program and may avoid high purchased power and transmission costs incurred for peak periods or contingencies. The costs of marketing the programs, and even payments to participants, may appear in a customer service account, such as Account 908. Despite their location in this account, the costs are not customer-related. They are resource costs that benefit all customers.

Utility demand response programs are designed to avoid capacity and energy costs and line losses for short-duration loads during times of system stress. The program costs may include investments and expenses at utility offices (computers, software and labor), installations on the distribution system (sensors and communication equipment) and installations on customer premises (controls). These costs are incurred to avoid peak capacity (and sometimes associated energy) costs on the generation system and sometimes on the transmission and distribution systems as well.

The demand response costs should be functionalized across all affected functions and allocated based on metrics of peak usage that relate to the period for which they are incurred — the hours contributing to highest stress. Where demand response provides benefits outside the highest-stress hours, such as by providing operating reserves (which reduce the need to run uneconomic fossil-fueled generation), a portion of the demand response costs should be allocated to the hours when demand response provides those benefits.

Some investments provide not only demand response but also load shifting or energy efficiency. Examples include controls for water heaters, space cooling and space heating and swimming pool pumps. These programs can reduce energy costs, including increasing load in periods with excess renewables that would otherwise be curtailed. Allocation of these costs should reflect the mix of benefits, including peak reductions, reduced reserve costs and reduced energy costs.

For programs that are operated only infrequently under conditions of bulk generation shortage (e.g., industrial interruptible load), the loads that were curtailed should be added back to the relevant class loads, and the costs of the programs — both outreach and incentive payments — should be treated as purchased power and allocated either to generation demand or to the specific hours when the program could be called.[183] Some utilities remove interruptible demand from the associated class load before allocating costs and allocate the costs of the program back to the participating class; that approach can be reasonable, as long as the interruptibility provides benefits equivalent to the utility functions for which the class allocation is reduced.[184] In no case should a cost of service study both reduce the participant class loads for demand response and allocate the costs to all classes; that would double count the benefit to the participating class.

Other programs with more frequent operations or wider benefits than emergency bulk generation should be assigned more broadly to generation, transmission and distribution based on program design. For example, if a demand response or storage program is developed simultaneously to improve the reliability and efficiency of the distribution system (i.e., a targeted nonwires alternative investment program) and to provide bulk power benefits, the costs could be assigned partly to each function as discussed above.[185]

In certain cases, utilities may directly own demand

183 It is generally inappropriate to pay customers to participate in a demand response program, subtract demand response capacity from the loads used for deriving allocation factors and also allocate the costs of the program to nonparticipating classes. Paying the participants and reducing their class loads pays twice for the same resource. The participants should be paid, of course, but all load should pay for the service that the program provides.

184 Many legacy interruptible rates require long lead times, allow only a limited number of annual interruptions, limit the length of each interruption and allow customers to ride through an interruption for a modest penalty. These rates may reduce the cost of serving the interruptible customers but do not fully replace equivalent amounts of generation and transmission.

185 Although a program theoretically could be designed only to have targeted distribution benefits without bulk power benefits, that may not be the most cost-effective program design.

response or load management equipment at customer premises to enable utility or consumer control of space conditioning, water heating, irrigation pumping and other loads. This type of investment's primary purpose is to enable peak load management, but it may also provide ancillary services and shifting of energy between periods. Although located within the distribution system, it is functionally different from most other distribution system plant in that it directly offsets the need for generation and transmission expenditures. For this reason, these costs should be classified and allocated differently from other distribution plant.

14.3 Treatment of Discounts and Subsidies

The decision to reduce the revenue responsibility of some customers increases the revenue responsibility of other customers. There are a variety of reasons for legislatures and regulators to provide discounts. Some are cost-based (such as for off-peak or interruptible service), in which case other customers are not truly providing a subsidy. Other discounts are truly subsidies, most commonly for low-income residential customers (unless justified by a substantially different load profile) and for financially distressed businesses — especially agricultural irrigation[186] and businesses that are major employers.

A common example is the difference between the revenues that low-income consumers would have paid under the standard residential tariff (or a tariff designed to recover the costs appropriately allocated to a low-income class) and what they actually pay under discounted low-income tariffs.[187] Where those subsidies exist, the cost of service study must address how to recover the subsidies through adding to the revenue responsibility of other customers. The decision as to whether the subsidy should be recovered from the class whose members receive the discount or from all customers is a matter of public policy, which is sometimes settled by the legislature[188] and other times left to the regulator's judgment. If the subsidy is recovered within the discounted class, the discount does not affect cost allocation to the class because the costs remain within the class and the subsidy shows up in the form of reduced revenues (and may thus result in higher rates for the remainder of the residential class). But if the subsidy is to be redistributed to other classes, it is appropriate for inclusion in the cost of service study as a cost or revenue adjustment to be apportioned across classes.[189]

As a practical matter, recovering a subsidy from the nondiscounted customers in the class receiving the discount may just push more of those customers into distress. Hence, the most reasonable manner of recovering a subsidy will vary: If the residential class is mostly affluent, with small pockets of poverty, dealing with a low-income discount entirely through rate design in the residential class may be appropriate. But if most of the residential class is in a tenuous financial condition, but the commercial and industrial classes in the territory are thriving, spreading the subsidy costs over all classes may be most appropriate, with a net credit to the residential class and charges to other classes, perhaps on an energy basis.

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186 For example, Nevada has a requirement that certain irrigators receive low rates: "IS-2 is a subsidized rate that NV Energy charges eligible agricultural customers who agree to interruptible irrigation pump service during certain situations. This service is applicable to electricity used solely to pump water to irrigate land for agricultural purposes. Agricultural purposes include growing crops, raising livestock or for other agricultural uses which involve production for sale, and which do not change the form of the agricultural product pursuant to NRS 587.290" (NV Energy, n.d.).

187 Low-income subsidies may be motivated by a combination of social concerns (such as reducing the burdens on needy customers and avoiding health-related problems of customers unable to heat or cool their homes), utility practicality (reducing bad debt and collection expenses) and cost causation. Low-income consumers are typically low-use customers and may tend to have less temperature-sensitive load that drives utility system peaks. Depending on the composition of the low-income population, they may also be at home in a different pattern than higher-income customers. A time-differentiated cost study may illuminate these differences.

188 For example, California Public Utilities Code § 327(a)(7) requires that the low-income electric rate for its IOUs be allocated by equal cents per kWh to all customers except recipients of the low-income rate and street lighting customers.

189 For example, a pro forma adjustment to revenue for each class (positive to the residential class; negative to other classes) would spread the subsidy across all the classes that the regulator concludes should contribute to this service.

15. Revenues and Offsets in Embedded Cost of Service Studies

15.1 Off-System Sales Revenues

Some retail cost of service studies treat wholesale sales as a separate class and allocate costs to the off-system customers. The cost of service study does not necessarily lead to any change in the off-system customers' charges (which are typically set by contracts, markets or FERC) but does help the regulator determine what share of the revenue requirement not recovered by FERC-regulated sales should be borne by each retail class. Alternatively, many utilities allocate all their costs to the retail classes and credit the export revenues back to the retail classes.[190]

In the latter approach, utilities sometimes allocate wholesale revenues to classes in proportion to their allocation of generation costs. Under this type of allocator, the greater the rate class's demand and usage, the greater its share of the off-system sales revenue. The problem with this approach is that some classes (e.g., industrials) use most of the generation capacity allocated to them throughout the year, while other classes typically pay for capacity they use in their peak season but which is available for sale in other seasons. Off-system sales revenues depend not only on the retail customers' financial support of the resources (including generating capacity) from which off-system sales are made but also on the extent to which class load shapes leave resources available to make those sales.

A more appropriate allocator would reward a class for having lower demand and usage, perhaps on a monthly basis, thereby leaving generation (and transmission) capacity available to support the off-system sales. In other words, the revenue from off-system sales should reflect classes' contribution to the availability of capacity to make the sales.[191]

15.2 Customer Advances and Contributions in Aid of Construction

As discussed in Section 11.2, most utilities charge new customers or new major loads for expansion of the delivery system, at least in some circumstances. Utilities frequently require customer advances for construction costs when they are asked to build a facility to accommodate subsequent load growth (e.g., to connect a subdivision or commercial development before some or perhaps any of the units are built and sold). The utility requires the advance to transfer to the developer the risk that the load will never materialize, or that load will grow more slowly than expected. As the load materializes, the advances are refunded to the developer. Those advances provide capital to the utility and generally are treated as a reduction of rate base; that cost reduction should be directly assigned to the customer classes for whom the advances were made.

Contributions in aid of construction are similar to customer advances but are applied in situations in which the utility does not expect the incremental net revenues from the load to cover the entire cost of the expansion. The contributions are thus a permanent payment to the utility, offsetting part of the capital cost. Contributions in aid of construction should be treated similarly to customer advances, allocated as

190 The same approach is possible with retail customers whose rates are fixed under multiyear contracts. Off-system sales revenues may vary considerably, based on market conditions, and are therefore often included in a fuel adjustment clause or similar rider between rate cases, while the base allocation is typically established in a general rate case.

191 MidAmerican Energy in Iowa proposed an hourly cost allocation method for capacity and energy in a recent case but also argued that if the Iowa Utilities Board were to use its traditional "average and excess demand" method instead, off-system sales margins should be allocated by excess demand, not by energy. "MidAmerican believes it is more appropriate to allocate wholesale margins (revenues less fuel costs) based on the excess demand component of the [average and excess] allocator, as it is from excess generation capacity that wholesale sales can be made" (Rea, 2013, p. 19).

rate base reductions for the class for which the contributions were made. Where that is not possible, they should be applied as realistically as possible to offset the rate base for the types of facilities for which the contributions were collected.

As noted in Section 12.2, customer deposits that offset rate base should be allocated consistently with uncollectible accounts expenses and late payment revenues.

15.3 Other Revenues and Miscellaneous Offsets

The treatment of other operating revenues affects customer class allocation. Some cost of service studies allocate all these revenues proportionally to a broad-based factor such as base rate revenue. Others do a more granular analysis. The granular analysis is preferable analytically because it is closer to the basis for the revenues.[192] There are several types of other operating revenue. Three of the largest are:

- Late payment revenues.
- Revenues for auxiliary tariffed services.
- Rents and pole attachment revenues.

As discussed in Section 12.2 earlier, late payment revenues need to be treated consistently with uncollectible accounts expenses and customer deposits.

Auxiliary tariffed service revenues result from directly charging customers for certain actions that customers take. The large majority of tariffed revenues result from items such as service establishment charges, charges for reconnection after disconnection, field collection charges and returned check charges. These revenues should not be allocated broadly because the revenues are predominantly paid by residential customers and the costs that these revenues reimburse are predominantly in customer-related accounts that are largely assigned to residential customers (accounts 586, 587, 901 to 903 and 905). These revenues should be directly assigned to the customer class that pays them or (if that is not possible) allocated in proportion to customer accounts expenses excluding uncollectibles.

Tariffed service charges for costs associated with opting out of AMI should be allocated in the same way as the costs of AMI opt-outs (as discussed in Section 12.1).

Rents should be allocated to the function causing the rents (distribution lines, office buildings, etc.). In particular, pole attachment revenues from cable and telecommunications companies should be allocated in proportion to poles.

192 For example, assigning revenues from service establishment charges based on total base rate revenue would result in large customers, who rarely move, receiving revenue as if they had moved many times in a single year.

16. Differential Treatment of New Resources and New Loads

In some situations, regulators have treated new resources or new loads using considerations that do not fit neatly into the embedded cost of service study framework. In particular, equity may sometimes be improved by reflecting the history and projections of class loads. However, there are risks in adopting such an approach, particularly within customer classes. Regulators should be careful to ensure adoption of such techniques is not arbitrary or discriminatory and is grounded in solid reasoning.

These differential treatment techniques are sometimes referred to as incremental cost of service studies[193] and can be conceptualized as either applying two different embedded cost techniques or combining an embedded cost technique with a marginal cost technique. In either case, the defining characteristic of these methods is the recognition that the costs associated with load growth in the recent past or the relatively near future, which typically might be several years, are being driven by a specific class or subclass of customers.

Incremental cost considerations are sometimes used to address a special circumstance that justifies differential treatment for particular classes or subclasses of customers within the context of an embedded cost study. Examples include:

- Allocating legacy low-cost generation resources to classes in proportion to their contribution to loads in a past year (perhaps the last year in which those resources were adequate to serve load), with the higher incremental costs of newer generation allocated to classes in proportion to their load growth since that base year.
- Setting the revenue requirements for selected classes or subclasses at levels below the general cost allocation but higher than near-term incremental costs; for example, in determining how to apportion the cost burden of economic development programs or low-income assistance programs.
- Developing desired end uses that may require preferential rates in the short term (e.g., electric vehicles or docked ships that would otherwise be burning oil) to provide a societal benefit or stimulate a desirable market.

In most cases, the differential treatment is intended to protect customers in the other classes from higher costs of new resources or from bearing a larger share of legacy costs.

16.1 Identifying a Role for Differential Treatment

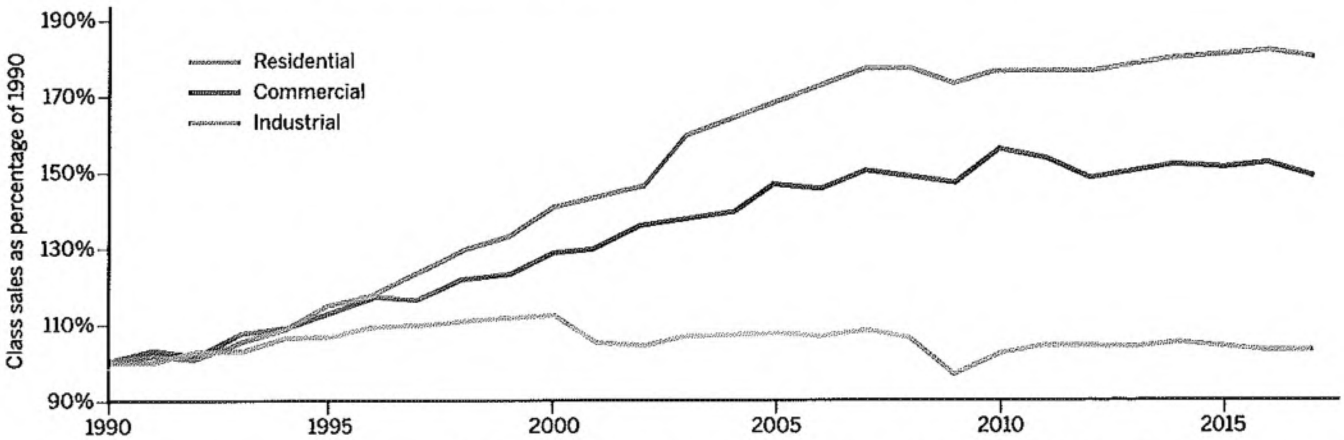
A study with differential treatment typically looks at the costs the system will incur within a relatively short time horizon to serve new load or retain existing load. The costs that may differ between the legacy loads and resources and incremental loads and resources include the variable costs of existing generation resources and the costs of new supply resources, transmission projects and distribution upgrades.[194] In each case, inequities or inefficiencies arise because costs do not scale proportionally to the drivers, such as load. If the utility has committed generation resources, with low variable costs, in excess of its requirements and has overbuilt most of its transmission and distribution circuits, incremental costs will tend to be below average costs.[195] In contrast, in a period of tight supply, the near-term costs of running expensive generation and adding generation, transmission and distribution resources may be higher than embedded costs.

193 The term "incremental cost of service study" in this case is not used in the same sense as a marginal cost of service study, where the marginal impact of load patterns is measured.

194 In principle, there could be similar differences in the costs of some customer service elements, such as between an existing billing system that would be adequate indefinitely for the existing accounts and an expensive new system that would be required if the utility adds accounts.

195 Surplus capacity does not always imply that incremental costs are below average costs. If the utility can save money by selling surplus generation resources or shutting them down, the incremental cost of retaining or increasing load may be as high as the embedded costs or nearly so.

Figure 43. US load growth by customer class since 1990



Data source: U.S. Energy Information Administration. *Form EIA-861M Sales and Revenue: 1990-Current*

In some cases, growth has profound impacts on system costs, and special consideration of differential growth rates may be important to the regulator. Load growth at certain hours may be beneficial, while load growth at other hours may be problematic, requiring new resources. Those facilities may be more expensive than the existing equivalents due to any of the following:

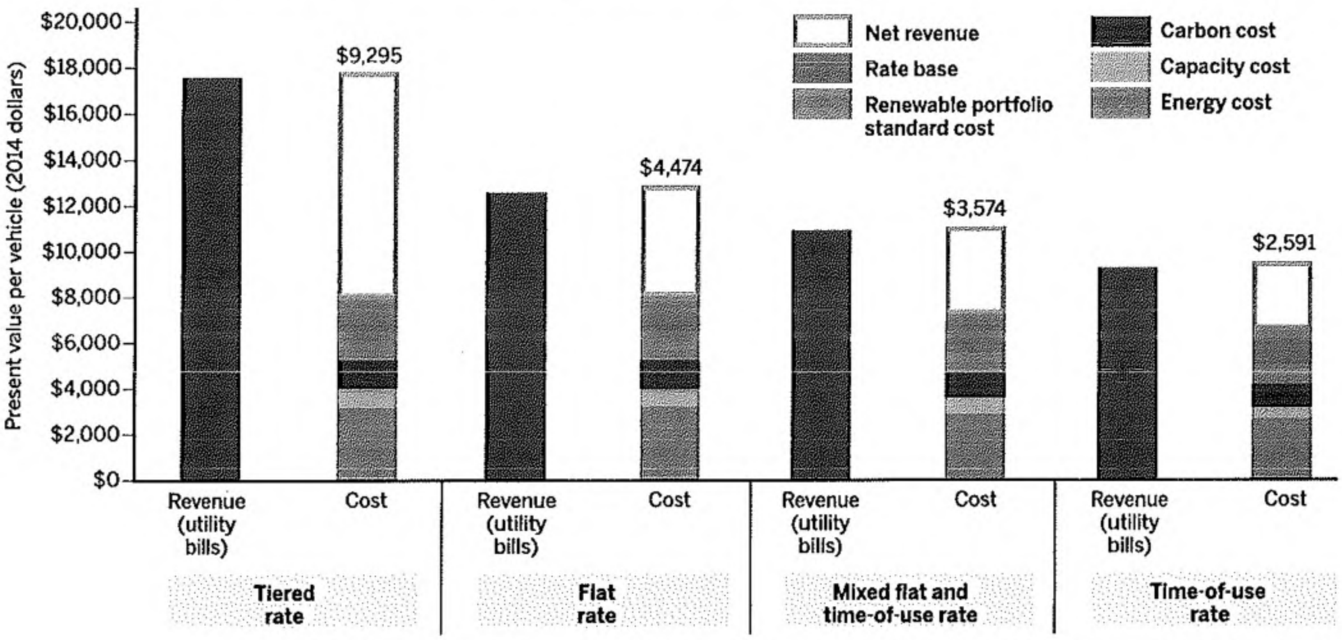
- Inflation: Equipment built 20 years ago will usually be less expensive than the same equipment installed today; buying new sites for generation or substations may be many times the embedded costs of sites purchased in the 1950s.
- Location: Existing generation may be located near load centers, while new generation may be required to locate much farther away; the existing distribution system may be relatively dense, while the new loads require long line extensions.
- Regulatory standards: The utility may be required to locate new lines underground;[196] environmental standards for routing, construction and emissions are often more restrictive for new resources than existing ones.
- Exhaustion of favorable opportunities: A utility may have relied historically on low-cost hydro, while its new resources may be much more expensive; ideal sites for wind power tend to be the first ones developed, while less favorable sites are generally developed later.
- The particular needs of the growing loads, such as higher reliability or power quality, or three-phase service in areas with mostly single-phase service.

Most traditional embedded and marginal cost studies do not take differential growth into account. U.S. residential loads grew about 50% from 1990 to the 2008 recession and not at all since; commercial loads grew about 80% up to the recession and slightly since; and total industrial electricity consumption grew slowly to about 2000 and has declined slowly since, as shown in Figure 43 (U.S. Energy Information Administration, n.d.-b). Load growth patterns for individual utilities may be much more disparate, both among customer classes and between clearly distinguishable subclasses (such as urban and rural, small markets and big-box stores, or farms and mines).

Where incremental costs are much higher than embedded costs, the difference may be assigned to classes in proportion to their growth. If it is a subset of a class that is growing quickly, there may be a rationale for adopting separate tariffs or riders for new customers within that class or for an identifiable subgroup contributing to higher costs (e.g., large vacation homes or data centers). The correct answer in some cases is the creation of a new customer class with separate load and cost characteristics. Beyond cost allocation, the incremental costs may be reflected in rate design and connection fees. For

196 Undergrounding may also be required by the difficulty in finding room for overhead transmission through built-up areas.

Figure 44. Estimated revenue and cost from serving additional electric vehicle load



Source: Energy and Environmental Economics. (2014). *California Transportation Electrification Assessment — Phase 2: Grid Impacts*

example, higher costs may also be allocated to the entire class but collected through a rate element (e.g., consumption over twice the monthly average) that aligns well with the customers causing the additional costs.

In some situations, load growth can reduce system average costs, at least temporarily, by spreading embedded costs over more units of sales. Regulators sometimes reduce rates to a special class or particular customers who will demonstrably generate more revenue with the lower rates, such as with economic development and load retention rates. At the present time, this may apply to beneficial electrification of transportation. Figure 44 shows a calculation of how additional electric vehicle load would generate additional net revenue, thus creating opportunity to benefit new EV users and existing consumers (Energy and Environmental Economics, 2014).

Some generation resources, such as federal hydropower entitlements, are made available to utilities by statute to serve particular loads, such as residential customers. Many regulators allocate those benefits to the classes whose entitlement to the power makes it available to the utility.[197]

16.2 Illustrative and Actual Examples of Differential Treatment

Table 37 on the next page shows an illustrative incremental cost study. In this simplified example, costs are rising; many are directly related to growth, but some are not. Costs relating to growth are assigned to the classes in proportion to their growth. Costs not related to growth are assigned based on each class share of current usage. The result, where both classes start at the same usage level but one grows four times as quickly as the other, is that the growth-related costs are assigned to the growing class, increasing its revenue responsibility if its costs are greater than current rates or decreasing its responsibility if its costs are lower than current rates.

In this illustration, both classes had equal rates in the previous rate proceeding. But costs have risen for both nongrowth categories (inflation) and growth categories (new resources and new distribution capacity). After application of an incremental cost study, the slow-growing class is assigned a rate averaging

197 Those benefits are often reflected in rate design by development of a lower first energy block to ensure that each eligible customer gets an appropriate share of the benefit.

14 cents per kWh, while the fast-growing class is assigned an average of 17 cents per kWh. In the opposite situation, where incremental costs are lower than average costs, the growing class might be assigned lower costs.

Table 37. Illustrative cost study with differential treatment of new resources

	Total	Residential	Commercial and industrial
Revenues at previous usage	$200,000,000	$100,000,000	$100,000,000
Previous usage (MWhs)	2,000,000	1,000,000	1,000,000
Current rates per kWh	$0.10	$0.10	$0.10
Usage			
In current rate period (MWhs)	2,250,000	1,050,000	1,200,000
Growth from previous (MWhs)	250,000	50,000	200,000
Class share of growth		20%	80%
Class share of current		46.7%	53.3%
Growth-related costs	$100,000,000	$20,000,000	$80,000,000
Nongrowth costs	$50,000,000	$23,335,000	$26,667,000
All increased costs	$150,000,000	$43,335,000	$106,667,000
Total revenue requirement	$350,000,000	$143,335,000	$206,667,000
Usage in current rate period (MWhs)		1,050,000	1,200,000
New rates per kWh		$0.14	$0.17

Note: Numbers may not add up to total because of rounding.

16.2.1 Real-World Examples

This section describes specific applications of differential treatment in cost allocation to illustrate the range of concepts.

Seattle City Light 1980 Cost Allocation

In 1980, Seattle City Light, a municipal utility, was experiencing rapid growth in commercial loads with stagnant to declining industrial loads. It recognized that continued growth would require it to commit to new nuclear or coal plants with incremental power costs much higher than the embedded hydro resources. Average rates were about 2 cents per kWh, while just the expected cost of new generation resources was about five times that level.

Even without the new resources, Seattle City Light required a rate increase and developed an interclass cost allocation method along the following lines:[198]

- Starting with historical-year sales by class and prior year revenues by class.
- Assigning the costs related to growth in proportion to the sales to each class, using forecast sales and expected long-term resource acquisition costs.
- Apportioning the residual revenue requirement increase on a uniform basis to all customer classes.

This approach resulted in an average increase in residential rates, an above-average rate increase to commercial customers and a below-average rate increase to industrial customers. It achieved the stated equity goal of charging more to the fastest-growing customer class — that is, the class that was driving the lion's share of the incremental costs.

Vermont Hydro Allocation

The state of Vermont receives an allocation of low-cost power from the Niagara and St. Lawrence hydroelectric facilities owned by the New York Power Authority, pursuant to a requirement in statute that allowed construction of the plants, to provide power to Vermont.[199] The Burlington Electric Department allocates this power to the residential customer class.[200] Other classes do not benefit from this resource. This is a method of ensuring that limited low-cost

198 One of the authors of this manual, Jim Lazar, participated in this proceeding on behalf of an intervenor.

199 "In order to assure that at least 50 per centum of the project power shall be available for sale and distribution primarily for the benefit of the people as consumers, particularly domestic and rural consumers, to whom such power shall be made available at the lowest rates reasonably possible" (Niagara Redevelopment Act, Pub. L. No.85-159, 16 U.S.C. § 836[b][1]). NYPA was required to provide a portion of the power to public bodies and co-ops in neighboring states (16 U.S.C. § 836[b][1]). Thus, the resources were made available to the Burlington Electric Department for the purpose of benefiting residential customers.

200 The Burlington Electric Department also uses that allocation to create an inclining block rate design consisting of a customer charge to cover billing, collection and other customer-specific costs; an initial block priced at the New York Power Authority cost plus average T&D costs; and a tail block that pays for other generation resources plus average T&D costs. See Burlington Electric Department (2019).

resources are equitably allocated to the customers for whom the New York Power Authority provides the power and that all customers share the cost of incremental resources needed to serve demand in excess of incremental usage.[201]

Northwest Power Act — New Large Single Loads

The Pacific Northwest Electric Power Planning and Conservation Act of 1980 provided, among other things, for division of the economic benefits of the federal Columbia River power system among various customer groups and rate pools (Pub. L. No. 96-501; 16 U.S.C. § 839 et seq.). The act set forth a specific mechanism for the Bonneville Power Administration to charge a price based on new resources to "new large single loads" (discrete load increments of 10 average MWs or 87,600 MWhs per year, such as might be experienced if a new oil refinery were built). This provision was intended to protect existing consumers from rate increases that could result from new very large loads attracted by the low average generation costs in the region, in a period in which new resources were very expensive. Table 38 shows average rates for Bonneville Power Administration by category for recent years, including a higher rate for new resources (Bonneville Power Administration, n.d.).[202]

Table 38. Bonneville Power Administration rate summary, October 2017 to September 2019

Rate category	Average rates per MWh
Priority firm public utility average	$36.96
Priority firm public utility Tier 1	$35.57
Priority firm – IOU residential load	$61.86
Industrial power	$43.51
New resources	$78.95

Source: Bonneville Power Administration. *Current Power Rates*

Nova Scotia Power Load Retention and Economic Development Rates

In 2011, falling global demand for paper resulted in the bankruptcy and shutdown of two paper mills that were Nova Scotia Power's largest customers, which accounted for about 20% of its sales and 12% of its revenues. The mills had been major employers, both directly and as purchasers of wood harvested from forests in the province. A buyer emerged for the larger of those facilities, contingent on a variety of supportive policies from the provincial and federal governments, including favorable tax treatment and rates.

Nova Scotia Power proposed and the Nova Scotia Utility and Review Board approved (with modifications) a load retention rate that would charge the mill hourly marginal fuel and purchased power costs (including opportunity costs from lost exports), plus administrative charges and mill rates to cover variable O&M, variable capital expenditures and a contribution to capital investments and long-term O&M. The load would be entirely interruptible, and the utility committed to excluding the mill's load from its planning and commitment decisions (Nova Scotia Utility and Review Board, 2012).

The determination of Nova Scotia Power's hourly marginal costs proved to be more difficult than expected.[203] Nonetheless, the rate design succeeded in attracting the investment necessary to restart and retain the mill as an employer while producing some contribution to Nova Scotia Power's embedded costs. The load retention tariff expires in 2020, at which time the mill may switch to a firm rate or negotiate a new load retention tariff.[204]

Chelan County Public Utility District Bitcoin Rate

The creation of bitcoin cryptocurrency units requires energy-intensive mathematical computations called mining. To limit the cost of their operations, bitcoin "miners" have sought locations with low-priced electricity. Those operations

201 This same concept has been the foundation of inclining block rates in Washington state and Indonesia.

202 The average rates subsume a variety of fixed and variable charges.

203 Nova Scotia Power was not part of an energy market and had limited connections to its only neighboring utility (NB Power, which is also not part of an energy market), and its marginal generation resources are coal plants with long commitment horizons (Rudkevich, Hornby and Luckow, 2014).

204 The Nova Scotia Power system will operate differently after 2020, when it is expected to have access to large amounts of Newfoundland hydro energy and operate under stricter carbon emissions standards. Any new load retention tariff would need to reflect those changes.

typically require very large amounts of power but have few on-site employees and little local economic benefit. One of these locations is Chelan County in Washington state, where the local public utility district owns two very large dams on the Columbia River and has industrial rates about one-fourth of the national average.[205]

Chelan County Public Utility District's existing low-cost resource is fully obligated to a combination of local retail use and long-term contract sales. The contract sales prices are above the average retail rates, bringing significant revenue to fund public infrastructure in the county, including a world-class parks network. When the district received applications for service from bitcoin miners, it decided that this high-density load growth would not be in the public interest, declared a moratorium on new connections and developed a tariff designed to ensure that any growth of this type of load would not adversely affect other consumers or the local economy (Chelan County Public Utility District, 2018). This tariff is geographically differentiated, to recognize areas where transmission and distribution capacity are available, and includes:

- Payment in a one-time charge of transmission and distribution system costs to serve large new loads.
- A price for electricity, tied to (generally higher) regional wholesale market prices, not Chelan County Public Utility District system costs.
- Severe penalties for excess usage that could threaten system reliability.

205 The Chelan County Public Utility District rate for primary industrial customers up to 5 MWs with an 80% load factor is 1.91 cents per kWh (Chelan County Public Utility District, n.d.). The average U.S. industrial price was 6.88 cents per kWh in 2017 (U.S. Energy Information Administration, 2018, Table 5.c).

17. Future of Embedded Cost Allocation

Change is inevitable as the electric industry adapts to new technology. Part III of this manual, on embedded cost of service studies, has attempted to address many common situations the cost analyst will face in determining an equitable allocation of costs among customer classes. But new technologies and changing loads will dictate new issues and perhaps new methods.

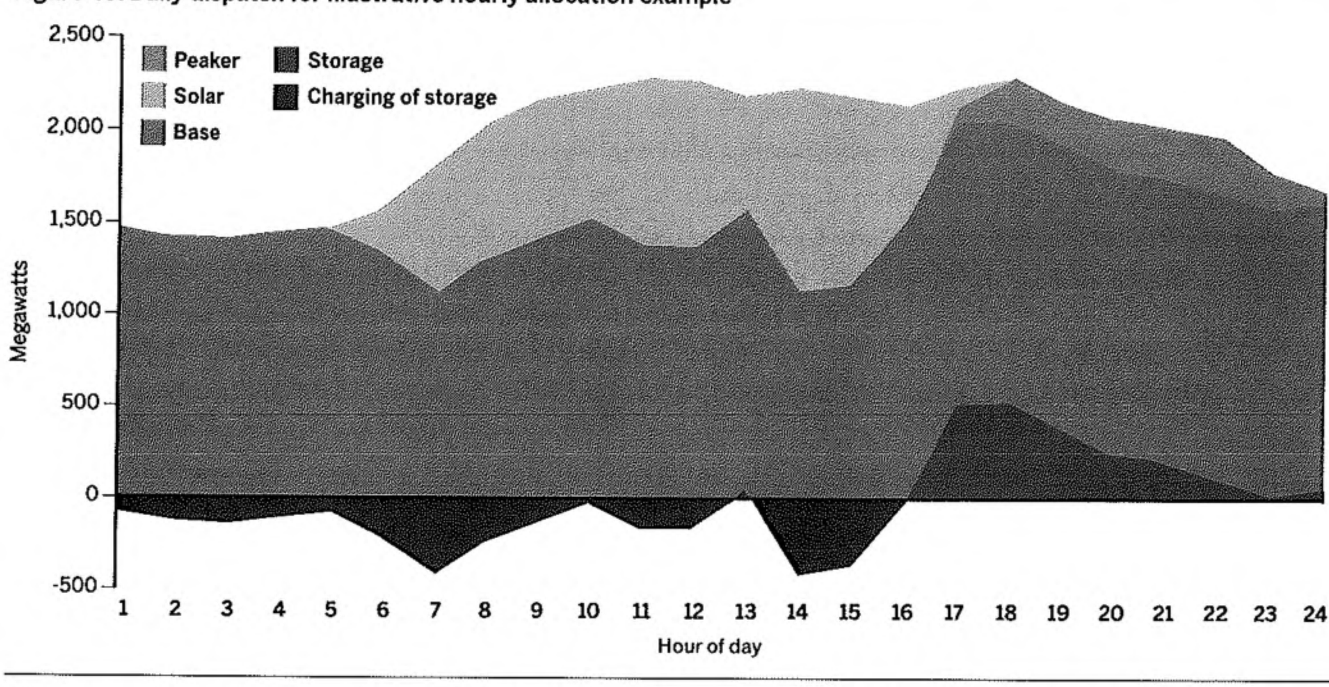
Historically, power has flowed from central generators, through transmission, to primary distribution and then secondary distribution. Customers served at the transmission level have not paid for distribution, and those served at primary have not paid for line transformers or secondary lines. This situation is beginning to change. In some places, the development of distributed solar capacity already causes power to flow from secondary to primary and even onto the transmission system. At some point, all customers may receive service through all levels of the delivery system, requiring a substantial rethinking of the allocation of distribution costs.

In addition to the increased complexity of system operations, utilities have more data about system operations and customer loads than they had a few decades ago. As the costs of electronics decline, more data will become available to more utilities. Thus, methods that were the best available in the 1980s can now (or soon) be superseded by more accurate and realistic allocations. Computations that would have been unwieldy on the computers of the 1980s are trivial today.

For example, as utilities acquire data on the hourly load of each class, many costs can be allocated on an hourly basis, rather than on such summary values as annual energy use and contribution to a few peak load hours. The costs of baseload generation resources (nuclear, biomass, geothermal) may be assigned to all hours; costs of wind and solar resources to the hours they provide service; storage to the hours in which it exports energy and provides other benefits;[206] and demand response costs to the hours these resources are deployed or the hours in which they reduce costs by supplying operating reserves. In a sense, this is an evolution and refinement of the base-intermediate-peak traditional method, described in Section 9.1.

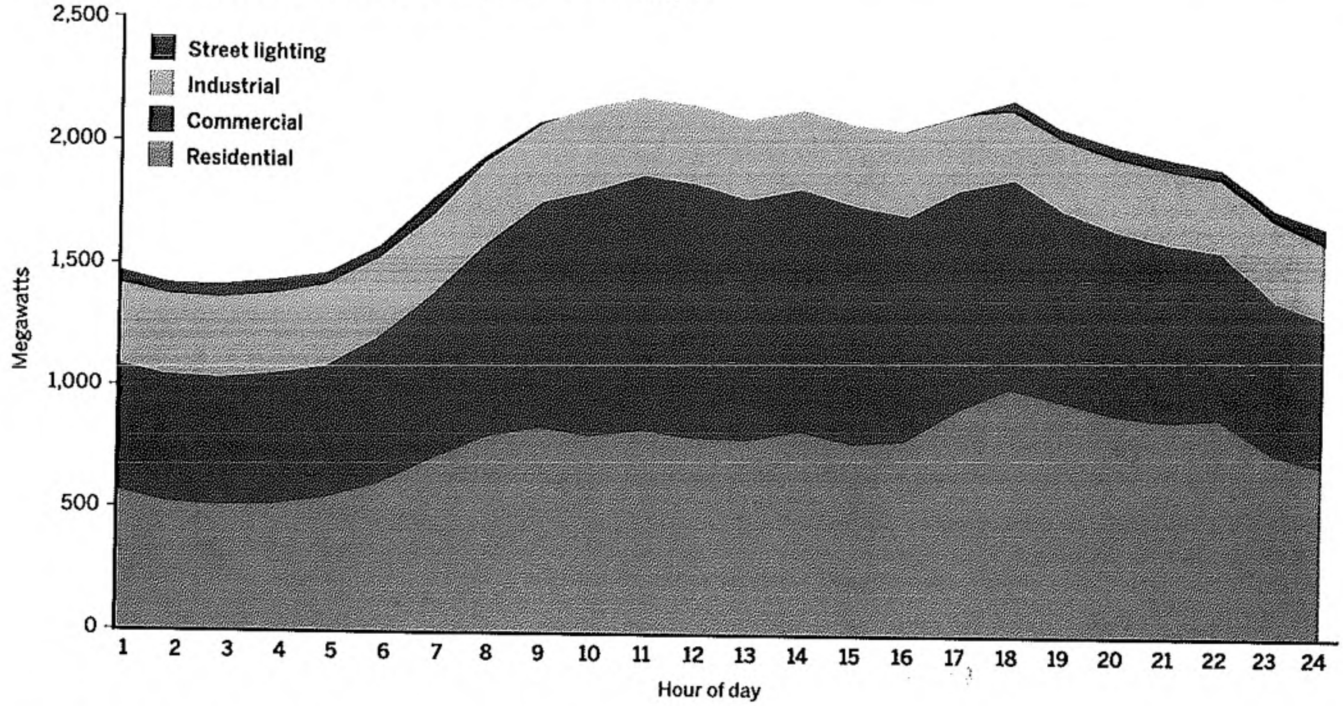
To illustrate this approach, Figure 45 provides a day's

Figure 45. Daily dispatch for illustrative hourly allocation example



206 Among other things, charging storage in hours with low net loads will raise minimum load levels and reduce ramp rates, benefiting the hours in which net load rises rapidly.

Figure 46. Class loads for illustrative hourly allocation example



worth of hourly dispatch of four resources: a baseload resource (perhaps nuclear), solar, a peaker (perhaps a combustion turbine) and storage (both as charging load below the axis and generation above the line). In this example, the storage charges from excess base capacity in the early morning and then from solar, and discharges in the evening to replace the waning solar. The actual application of hourly allocation would include 8,760 hours from an actual or typical year, with a wide range of load levels, availability of the base resource and solar output patterns.

Figure 46 provides hourly energy requirements by class (including losses) for the same day as in Figure 45.

Table 39 on the next page provides two types of data from Figure 45 and Figure 46: each class's share of the load in each hour, and the portion of each resource's daily generation that occurs in the hour.

The generation cost allocation for a class would be:

$$\sum_{r,h} L_h \times S_{r,h} \times C_r$$

Where L_h = class share of load in hour h

$S_{r,h}$ = share of resource r output that occurred in hour h

C_r = cost of resource (in this example, for the day)

Table 40 shows the result of this computation for the data in Table 39. The lighting class, for example, would pay for 1.8% of the base resource, 2.2% of the peakers and just 0.6% of the solar. Table 40 also shows each class's share of total load, for reference.

Table 39. Hourly class load share and resource output

	Class share of load				Resource output: Percentage occurring by hour			
Hour	Residential	Commercial	Industrial	Street lighting	Base	Peaking	Solar	Storage
1	39.0%	35.3%	22.5%	3.2%	4%	0%	0%	0%
2	37.0%	36.2%	23.5%	3.3%	4%	0%	0%	0%
3	36.4%	36.7%	23.5%	3.4%	4%	0%	0%	0%
4	36.7%	37.0%	23.1%	3.3%	4%	0%	0%	0%
5	37.5%	36.6%	22.7%	3.2%	4%	0%	0%	0%
6	38.4%	37.2%	21.4%	3.0%	4%	0%	3%	0%
7	39.7%	37.1%	20.6%	2.6%	4%	0%	8%	0%
8	39.8%	39.2%	19.5%	1.6%	4%	0%	9%	0%
9	38.8%	42.6%	18.4%	0.2%	4%	0%	9%	0%
10	36.7%	44.8%	18.2%	0.2%	4%	0%	8%	0%
11	36.6%	45.1%	18.1%	0.2%	4%	0%	11%	0%
12	35.9%	45.8%	18.1%	0.2%	4%	0%	10%	0%
13	36.7%	44.8%	18.3%	0.2%	4%	0%	7%	1%
14	37.5%	44.0%	18.2%	0.2%	4%	0%	13%	0%
15	36.3%	44.7%	18.8%	0.2%	4%	0%	12%	0%
16	37.4%	43.5%	18.8%	0.2%	4%	0%	7%	0%
17	41.5%	40.6%	17.4%	0.4%	4%	5%	1%	25%
18	44.7%	37.3%	16.1%	2.0%	4%	13%	0%	25%
19	45.2%	35.8%	16.8%	2.2%	4%	13%	0%	18%
20	44.2%	36.1%	17.4%	2.3%	4%	15%	0%	12%
21	44.4%	35.4%	17.8%	2.3%	4%	15%	0%	10%
22	45.9%	33.8%	17.9%	2.4%	4%	19%	0%	5%
23	42.8%	35.1%	19.4%	2.6%	4%	12%	0%	1%
24	41.6%	35.5%	20.1%	2.8%	4%	6%	0%	3%
All hours	39.7%	39.6%	19.1%	1.6%	100%	100%	100%	100%

Note: Percentages may not add up to 100 because of rounding.

Table 40. Class shares of resource cost responsibilities and load

	Residential	Secondary commercial	Primary industrial	Street lighting
Resource type				
Base	39.6%	39.2%	19.4%	1.8%
Peaker	44.3%	35.8%	17.7%	2.2%
Solar	37.5%	43.1%	18.7%	0.6%
Storage	43.8%	37.4%	17.2%	1.7%
Class share of total load	39.7%	39.6%	19.1%	1.6%

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Part IV:
Marginal Cost of Service Studies

18. Theory of Marginal Cost Allocation and Pricing

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

Economic efficiency is served when prices reflect the true value of the resources being used to serve customers' loads.

Marginal cost studies start from a similar functionalization as embedded cost studies: generation, transmission, distribution. However, the data used are not at all the same as those used in an embedded cost of service study. The typical marginal cost of service study requires detailed hourly data on loads by customer class, marginal energy costs and measures of system reliability (loss-of-energy expectation, peak capacity allocation factor, probability of peak, etc.), as well as multiyear data on loads and investments for the transmission and distribution system.

As will be discussed below with specific examples and applications, the time horizon of marginal cost studies and even of individual components within studies can vary. Marginal costs can be measured in:

- The short run, as with energy costs measured for one to three years, and all capital assets kept constant.
- Intermediate periods ranging from six years (the length of two typical general rate cases for many utilities) to 15 years (often used for analysis of T&D capital investments).
- The long term, such as with **long-run incremental costs** for the entire generation function; long-run generation capacity costs based on equilibrium conditions; and the rental of customer equipment in some marginal customer cost studies. The longest possible analysis would be a total service long-run incremental cost study where an optimal system is costed out.

At one extreme, a true short-run marginal cost study will measure only a tiny fraction of the cost of service that varies from hour to hour with usage and holds all other aspects of the system constant. At the other extreme, a TSLRIC study measures the cost of replacing today's power system with a new optimally designed and sized system that uses the newest technology. In between is a range of alternatives, many of which have been used in states like Maine, New York, Montana, Oregon and California to determine revenue allocation among classes. The major conceptual issue in these studies is using very short-run metrics for energy cost and longer-term metrics for capital costs (generation, transmission and distribution capacity and customer connection costs). Many studies use these mixed time horizons, but this is an error that should be avoided.

Marginal cost pricing generally is not connected to the utility's revenue requirement, except to some extent in restructured generation markets (where the costs are not subject to traditional cost of service regulation). The calculated marginal costs may be greater or less than the allowed revenue requirement, which is normally computed on an accounting or embedded cost basis. It is only happenstance if marginal costs and embedded costs produce the same revenue.

There is also no necessary connection between marginal cost pricing and cost allocation. To summarize the material discussed in more depth below, in its simplest hypothetical form, a marginal cost study computes marginal costs for different elements of service, and these are multiplied by the determinants for each class. This produces a class marginal cost revenue requirement and, when combined with other classes, a system MCRR. This is then reconciled with the allowed revenue requirement to determine revenue allocation by class. This part of this manual provides some examples of marginal cost studies and the revenue allocation resulting from them.

A second important concept related to marginal cost pricing comes from the theory of general equilibrium: If costs are in equilibrium, short-run marginal costs equal long-run marginal costs. That is, to get one more unit from existing resources would require operating resources with high variable costs, at a cost equal to the cost of both building and operating newer, cheaper resources. However, it is hard to apply this theory in practice because developing and quantifying a system in equilibrium is extremely difficult. Until recently, assets tended to be developed in large sizes relative to the utility's overall system needs, rendering equilibrium conditions unlikely. Equilibrium is also impossible in the real world, for three main reasons. First, loads and fuel prices can never be forecast exactly (and often cannot be forecast even closely). Technology also changes, and the use of specific resources ends up changing. Finally, long lead times to construct various resources (particularly large power plants and transmission lines) can exacerbate the consequences of forecasting errors.

As a result, the marginal cost methods used today, such as those developed by National Economic Research Associates (now NERA Economic Consulting) — discussed in considerably more detail throughout Part IV — do not reflect equilibrium conditions. Moreover, with the current configuration of the electric system and changes over time, the trend has been toward overbuilding, so generation marginal cost ends up systematically below average cost, with ramifications for class allocation. In addition, as previously implemented in many jurisdictions, the definitions of marginal cost have mixed short-term and long-term elements in ways that are theoretically inconsistent.

18.1 Development of Marginal Cost of Service Studies

The most common method used in jurisdictions relying on marginal costs for allocation purposes was developed by Alfred Kahn and colleagues at NERA in the late 1970s.[207]

The Kahn/NERA method (referred to as the NERA method in this manual because that is the term most analysts and practitioners use) is the predominant method that current marginal cost analysts use. Some entities, such as Oregon, use a long-run marginal cost method for generation, and other states and analysts have proposed changes to specific components of the NERA method. Nevertheless, the NERA method, whatever its benefits and detriments, is the starting point for most current marginal cost of service study analysis, and marginal cost of service study analysts have identified fewer alternative methods than have embedded cost of service study analysts.

Another practical consideration in analyzing marginal cost methods is that very few states are marginal cost jurisdictions. In particular, California, Nevada and Oregon calculate marginal costs for generation and other functions; Maine and New York have deregulated generation but use marginal costs for distribution. Thus, many examples in the remaining discussion come from a relatively small number of jurisdictions.

The NERA methodology uses:

- Long-term customer costs based on the cost of renting new customer connection equipment using the current technology.
- Intermediate-term transmission and shared distribution costs based on an analysis of additions made to serve new capacity but not to increase reliability or replace existing capacity to continue to serve load, measured over 10 to 15 years.
- Generation capacity costs that tend toward a longer term based on new construction.[208]
- Usually relatively short-term marginal energy costs (one to six years).

207 National Economic Research Associates developed a series of papers on the topic. The most critical for this manual are *A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States* (1977a) and *How to Quantify Marginal Costs* (1977b).

208 Some utilities and consumer advocates have used shorter-term generation capacity costs. Consumer advocates often chose shorter-term generation costs when revenue allocation was done by function rather than in total. See Section 19.3.

One of the key concepts developed through this work was the real economic carrying charge. A RECC takes the revenue requirements or costs of a resource and reshapes them to reflect a stream of costs that increases with inflation and has the same present value as the revenue requirements. Inputs to a RECC are the same as those used for utility revenue requirements. They include the capital structure and cost of capital, a discount rate, income tax parameters (rates, depreciation and whether specific tax differences are normalized or flowed through), book depreciable life and costs of property taxes and insurance. The RECC is not unique to this method but can be used in conjunction with other methods, such as long-run incremental cost of generation (see Section 19.1) or total service long-run incremental cost (Section 25.1).

Analytically, the RECC also reflects the value associated with deferring a project from one year to the next and can be used to place projects with different useful lives on a common footing. The RECC is lower than the utility's nominal levelized cost of capital for a given type of plant and lower than the early year revenue requirements calculated traditionally for such a plant. A further discussion of the RECC, with a specific example, is in Appendix B.

The mismatch of long-run and short-run marginal costs among cost components is particularly problematic in the NERA method. If system costs are allocated using the total measurement of generation costs based on relatively low shorter-run costs for energy and generation (that do not consider the value of capital substituting for energy over time) and much longer-term costs for the distribution and customer functions, the study will mathematically give too much weight to distribution costs in a marginal cost study, to the detriment of small customers. Analysts have used a number of methods to ameliorate or counteract this mismatch. These methods are briefly identified here but discussed in more detail in the sections noted.

- Developing a longer time horizon for generation costs (see Chapter 19 and Section 25.1). Various methods include:
    - Extending the time horizon for marginal energy costs and including carbon dioxide reductions and renewable costs as adders to short-run marginal energy costs.
    - Using long-run incremental costs, including full costs of new construction of generation.
    - Applying the new paradigm of long-run incremental cost analysis, at least for generation, explicitly to include the energy transition to renewables for generation and storage and demand response for capacity.
- Using short-run customer costs based on the direct costs of hooking up new customers as a better match with short-run energy costs (see Chapter 21).
- Ignoring joint and common costs, reducing long-run A&G costs that are assigned to functions other than energy (see Chapter 22).
- Reconciling on a functionalized basis (generation, transmission and distribution by the marginal costs of those functions) instead of on a total cost basis (see Chapter 24).

Another important issue NERA addressed was the method used to reconcile marginal costs to the system revenue requirement. The calculated marginal costs may be greater or less than the allowed revenue requirement, which is normally computed on an accounting or embedded cost basis. Thus, methods such as the equal percent of marginal cost approach are sometimes used for reconciliation, but some analysts prefer to use the **inverse elasticity rule**, where elastic components of usage are priced at the measured marginal cost, while inelastic components of usage are priced higher or lower than marginal cost to absorb the difference between embedded and marginal costs. This issue is discussed further in Chapter 24.

In the NERA method, the functionalization and then classification of system costs as energy-related, demand-related and customer-related is performed, just as in a traditional embedded cost of service study. The marginal cost of each of these elements is then estimated using a wide variety of techniques. These marginal costs are then multiplied by the billing determinants for each class to obtain the marginal cost by class, commonly referred to as the marginal cost revenue requirement. The MCRR is then reconciled to embedded costs and allocated across the classes. Each set of billing determinants used in the calculation is developed on a class

Table 41. Illustrative example of allocating marginal distribution demand costs by two methods

	Residential	Small commercial	Medium commercial	Large commercial and industrial
Class coincident peak-based allocation				
Marginal cost per kW	$100	$100	$100	$98*
Probability of circuit peak (MWs)	5,900	1,000	3,800	1,500
Marginal cost revenue requirement for distribution demand	$590,000,000	$100,000,000	$380,000,000	$147,000,000
Share of costs	48%	8%	31%	12%
Customer noncoincident peak demand allocation with diversity				
Marginal cost per kW	$100	$100	$100	$98*
Noncoincident peak demand (MWs)	23,878	3,131	7,482	3,561
Effective demand factor	36%	37%	65%	76%
Noncoincident peak demand multiplied by effective demand (MWs, rounded)	8,600	1,150	4,850	2,700
Marginal cost revenue requirement for distribution demand	$860,000,000	$115,000,000	$485,000,000	$264,600,000
Share of costs	50%	7%	28%	16%

*Lower marginal cost of large commercial/industrial reflects lower line losses on primary distribution loads.
Note: Percentages may not add up to 100 because of rounding.

Sources: Southern California Edison. (2017). *Errata to Phase 2 of 2018 General Rate Case: Marginal Cost and Sales Forecast Proposals; 2018 General Rate Case Phase 2 Workpapers*; additional calculations by the authors

basis and, except for the customer-related costs, is divided into time periods and provided for the year as a whole.

For the energy-related costs, the allocation is relatively straightforward, multiplying energy use in each time period by the energy cost in each time period. For the generation capacity costs related to reliability at peak, the allocation typically has not been done using the coincident peak methods most commonly used in embedded cost analysis (and discussed in Section 9.3). Instead, marginal costs are typically allocated over a larger number of hours. This allocation has been done using (1) loss-of-energy expectation, (2) an allocation factor spread equally over the top few hours (100 to 300)[209] or (3) peak capacity allocation factors, effectively a hybrid between the two other methods.[210]

For transmission and distribution costs, the methodology is not as settled, even among marginal cost jurisdictions. Allocation has been either coincident peak-based (related to the probability of peaks on distribution elements) or noncoincident demand-based, with adjustments for diversity between the load at the customer and load at the circuit or substation transformer (which can be developed through statistical analysis). Table 41 illustrates how the two methods can produce

209 This method was developed in California after restructuring in the late 1990s for use in allocating certain transition costs, because generation was expected to be competitive and loss-of-load probability was expected not to exist in a competitive market. San Diego Gas & Electric used the top 100 hours method for allocation of generation costs until 2012 (Saxe, 2012, Chapter 3, pp. 4-5). The company ultimately switched to loss-of-load expectation in 2014 (Barker, 2014). The top 100 hours are still used for allocation of the remaining transition costs of all the major California utilities.

210 Pacific Gas & Electric uses these. Every hour in excess of 80% of the peak is assigned a contribution to peak based on the load minus 80% of the peak. The mathematics mean that the peak hour has an allocation that is 20 times the allocation of an hour that is 81% of the peak and twice the allocation of an hour that is 90% of the peak. In past cases, the company used the gross load curve for both generation and distribution; in 2016, it switched for generation to the load curve net of wind and solar generation while using gross load for distribution. See Pacific Gas & Electric (2016), chapters 9 and 10.

substantially different outcomes (Southern California Edison, 2017a, 2017b, pp. 59-61 and Appendix B, with additional calculations by the authors).[211] Data from Southern California Edison were used because the company currently employs a hybrid of both methods.

Similar to its use of PCAF for generation allocation, Pacific Gas & Electric (PG&E) uses a PCAF method at the local level (each of its 17 divisions) for distribution costs (Pacific Gas & Electric, 2016, Chapter 10). Nevada uses an hourly allocation method based on probability of peak using the system peak demand from which its costs were calculated (Bohrman, 2013, pp. 3-8).

Analysts must be extremely careful when calculating the MCRR, particularly associated with T&D demand. The reason is that not all kWs are the same. Many utilities use one type of kW when developing a marginal cost per kW of demand or capacity (e.g., a kW of substation capacity, where there are 25,000 MWs of such capacity on a utility system) and then multiply the marginal costs by a kW that measures a different type of demand (for example, system peak demand where there are only 15,000 kWs of demand). In particular, when the marginal cost is measured based on a larger number of kWs than the kWs on which the cost is allocated, the result is to assign too few costs as demand-related; this overweights the customer costs in a distribution cost calculation. Additionally, controversy can arrive in measuring the kWs of demand for cost allocation. Although there is no hard and fast rule, two examples in Appendix C illustrate the concerns.

18.2 Marginal Costs in an Oversized System

T&D systems have tended to be oversized because equipment (transformers, wires, etc.) comes in fixed sizes. Moreover, oversizing could theoretically be cheaper in the long run than having to return to the same site to change out equipment, particularly when underground lines have been installed. Although it may be economically preferable in some circumstances, this oversizing tends to reduce intermediate-term marginal T&D costs below full long-run marginal costs or embedded costs.

Increased marginal costs for T&D do not necessarily result from high utility rates of return and strong financial incentives for rate base growth, as noted in almost every utility presentation and analyst report, because intermediate-term marginal cost methods usually have not included system replacements, as discussed in Chapter 20 and Appendix D. System replacements and incremental investments to improve safety and reliability (but not to serve new demand) are a large component of new T&D construction by utilities.

Generation is even more complex. Not only was it uneconomic in the past to build generation in small increments, but there were significant benefits of capital substitution (spending money on capital to reduce the use of expensive fuel) that created excess expensive capacity. In the past, when vertically integrated utilities built coal and nuclear plants, they would conduct planning exercises that provided a justification for those projects based on extremely long-term estimates of future fuel costs and future dispatch. As a result, large portions of the investment-related costs of these plants were justified based on savings of costly fuel and purchased power relative to building peaking generation. The forecast relatively high loads and high fuel prices did not always materialize, and long lead times of large projects meant they could not be economically changed or canceled in cases where the forecasts turned out to be wrong. The disconnect between generation construction and short-run marginal costs also resulted in stranded costs when restructuring took place.

A similar phenomenon occurred more recently as investments were made in expensive environmental retrofits of coal plants instead of retiring the units. Some of these investments ended up being uneconomic given lower than expected prices for natural gas and renewables, not to mention the prospect of greenhouse gas regulation.

For a number of utilities, a short-run marginal cost — assuming the existence of these future plants with high capital cost and low-cost fuel — was used to evaluate energy efficiency, renewables and CHP and to design rates. This methodology effectively gives preference to utility resources while depressing the avoided cost paid to independent power producers, finding less energy efficiency to be cost-effective,

211 Loads are rounded off to the nearest 50 MWs in the table, leaving out small classes and granular detail for ease of exposition.

and lowering incentives for customer-side response through rate design. Examples include Duke Power and Carolina Power and Light Co. from 1982 to 1985, which assumed that future coal and nuclear plants would be built when evaluating PURPA projects (Marcus, 1984, pp. 10-23). Another example is the calculations by Ontario Hydro for evaluation of energy efficiency and private power prior to and during the 1990-1993 demand/supply plan hearings at the Environmental Assessment Board (Marcus, 1988, pp. 14-16). A third, from 1990-1991 hearings, is Manitoba Hydro's analysis of energy efficiency using differential revenue requirement analyses assuming that the Conawapa hydro project would be constructed (Goodman and Marcus, 1990, pp. 132-133, F34-F45). Appendix E provides a mathematical discussion of this issue.[212]

Then, when excess capacity appeared, short-run marginal energy costs declined. The need for generation capacity also declined, although the extent to which that decline was recognized in short-run marginal cost methods varied across jurisdictions (see Section 19.3).

18.3 Impact of New Technology on Marginal Cost Analysis

Excess capacity can be the result of other cost transitions made for a combination of economic and environmental reasons — in particular, the transition to renewables and other related technologies (storage) that are not fuel-intensive.

18.3.1 Renewable Energy

Low-cost wind and solar resources are being installed to provide economic and environmental benefits and reduce fuel use even where capacity is not needed and in some cases are causing the retirements of older plants.[213] In some instances, the total cost of new renewable generation can be less than the fuel and O&M costs of generation that it displaces.

These resources have already been reducing short-term market prices in virtually all ISOs/RTOs. Short-run energy market prices are even sometimes negative in off-peak hours, due to generation that cannot shut down and restart for the next peak period and the renewable energy tax credits that make operating some resources profitable even if they need to pay for the market to absorb their energy output.

The renewable transition makes the traditional marginal cost methodology less relevant. Capacity costs and short-run marginal energy costs are low, while embedded costs remain high. Essentially a short-run marginal cost method sends price signals that energy is cheap because the fossil-fueled component of energy is being used less frequently and is becoming less costly when it is used, while generation capacity costs are also low unless artificially increased.

However, while short-run marginal costs are decreasing, embedded system generation costs are remaining at current levels or increasing because additional capacity is being brought on in advance of need. Other effects on utility generation revenue requirements arise because: (1) some renewables acquired relatively early may be relatively expensive compared with newer renewables in the face of declining cost curves; (2) the growth of renewables may be dampening growth in natural gas prices, which makes renewable energy look less cost-effective than it really is; and (3) in some cases, accelerated recovery of costs reflecting the early retirement of fossil-fueled and nuclear generation may raise embedded costs.

18.3.2 Other New Technologies

Smart grid resources can also reduce the marginal cost of distribution capacity by extending the ability to optimize the use of existing capacity. This may increase excess capacity in the short term while reducing long-run costs by substituting controls for wires and fuel. Sections 7.1 and 11.5 discuss in detail the technological characteristics of smart grid functions — including integrated volt/VAR **(volt-ampere reactive)** controls, automated switching and balancing of loads across circuits and enablement of demand response programs — and of storage and demand response resources.

In the near term, large-scale battery storage on the utility grid can be an economic substitute for peaking and relatively

212 Although not strictly a marginal cost issue, divergence between short-run and long-run marginal cost can be one reason for stranded costs (which tend to have been measured against an estimate of short-run cost over time).

213 An explicit example is Xcel Energy's program of substituting "steel for fuel" by replacing coal and gas with wind and solar generation (Xcel Energy, 2018).

> The technology-based economic transition to a smarter grid and a greater role for intermittent and storage resources will change the marginal cost paradigm.

inefficient intermediate gas-fired generation — including generation now receiving reliability-must-run (RMR) contracts in transmission rates — while reducing the cost of ramping to meet daily peak loads (Maloney, 2018; see also California Public Utilities Commission, 2018). This could reduce both marginal energy costs and marginal capacity costs if it proves ultimately to be cheaper than a combustion turbine. In the longer term of a decarbonized system with large amounts of intermittent resources, batteries are likely to need to operate for more hours.

If installed elsewhere on the system, particularly on the distribution system, storage batteries can not only provide support for generation and transmission but remedy distribution overloads or mitigate outages on less reliable radial distribution lines, especially where other smart grid functions are not feasible. The effect would be to reduce marginal capacity costs — although some portion of the cost of the storage should be included as a distribution capacity resource. Behind the meter, storage can provide demand response for the utility as well as significant benefits to customers.

Demand response (e.g., air conditioner cycling, interruptible customers) typically has been used as an emergency capacity resource to avoid bulk generation outages. But it could also be used (when coupled with smart appliances) to mitigate transmission and distribution overloads when the customer is at an appropriate voltage level, reducing future marginal costs.

18.4 Summary

The key issues associated with marginal cost analysis on a generic basis are:

- 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.
- Obsolete technique given changing resource options. Whether 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 depress the short-run prices of fossil-fueled energy and existing fossil-fueled capacity.
- Treatment of renewables. With the substitution of renewables (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. As an example, a wind plant that runs at 40% to 50% capacity factor (in the Southern Plains) depresses short-run marginal energy cost and may have no impact on capacity costs.
- Availability of storage. Storage is likely to have a lower cost of capacity than fossil-fueled capacity for at least some applications. It also provides more services than conventional peaking capacity depending on where it is sited — for example, it can provide some ancillary services (e.g., fast ramping service) and help with variable renewable energy integration. However, it may have the counterintuitive impact of depressing short-run marginal costs.

In essence, the technology-based economic transition to a smarter grid and a greater role for intermittent and storage resources will ultimately change the marginal cost paradigm from that used for the last four decades while blurring the traditional distinctions among generation, transmission and distribution costs. The short-run marginal cost paradigm based primarily on variable costs of fossil-fueled generation is becoming less central to the fundamental economics of electricity service for which regulation must account. That change has not been fully analyzed within the structure of marginal cost rate-making, but a pathway for such analysis will be discussed in Chapter 25.

19. Generation in Marginal Cost of Service Studies

The theory of marginal generation costs starts from the position that electric generation is a joint product, producing energy as well as capacity or reliability. When marginal cost methods were introduced in the 1970s, they constituted a significant advance over the previously used embedded cost theory that assumed that generation capital investment and nondispatch O&M costs are all demand-related and only short-term variable costs are energy-related. The marginal cost paradigm recognizes in some way, albeit imperfectly, that with a variety of generating plant technologies, capital can be substituted for energy and that all capital is not related to the need to serve peak demand.

19.1 Long-Run Marginal Cost of Generation

The first key 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 the Pacific Northwest, where large portions of the systems were energy-constrained. Hydro systems have very flexible capacity but depend on water for energy generation, and the supply of water is both limited under adverse conditions and not controllable. Under this method, the cost of new baseload generation in a resource plan was calculated as the total marginal generation cost. The cost of peaking generation (usually a combustion turbine) was determined to be the peak cost, and the remaining costs were energy-related.[214] In the past, the baseload generation cost was often a coal plant. This method has recently been modified in Oregon to use a combustion turbine for peak generation and a mix of combined cycle gas generation and wind generation for the nonpeak alternative (Paice, 2013, pp. 7-8).

The second long-run marginal cost option has been used by the California Public Utilities Commission for purposes other than cost allocation and rate design. Energy and Environmental Economics Inc. (E3) developed a relatively sophisticated hourly long-run incremental cost model.[215] The California commission has used the E3 model to evaluate energy efficiency, demand response and distributed generation for a number of years, although it has not yet used it for rate design. The generation components of this method have an evaluation period of up to 30 years. The model is designed to assume the short-run avoided cost until the year when capacity is projected to be needed and the full cost of a combined cycle generator if the long-run base total fossil-fueled generation cost is in equilibrium. The effect of this, in the past three decades, would have been to understate generation marginal costs compared with those that would exist under an equilibrium market. However, if the year of capacity need is set to the current year, which has been done in some recent analyses, the model becomes a full long-run marginal cost model, alleviating this problem.

E3 divides the costs into energy and capacity, with the costs of a simple-cycle combustion turbine (net of profits received for energy and ancillary services) treated as capacity-related and all remaining combined cycle costs as energy-related. The E3 model then shapes the energy costs into an

214 This method is similar to the equivalent peaker method (discussed in Section 9.1), except that it includes both capacity and energy.

215 The description of this method is taken from Horii, Price, Cutter, Ming and Chawla, 2016.

hourly load shape using information on load shapes over time (including changes resulting from renewable resource additions) and adds a projection of line losses, carbon dioxide costs and ancillary services to obtain a market price. To obtain the full marginal or avoided energy cost — to the extent that renewable resources (net of their resource-specific capacity credits) cost more than the energy-related cost of a combined cycle unit — the resulting extra costs of meeting the renewable portfolio standard over the 20-year period are added to the market-based costs.

19.2 Short-Run Marginal Energy Costs

Short-run marginal energy costs normally are 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). Marginal energy costs in the West — whether simulated directly or simulated through a market pricing version of a production cost model — typically have been dependent on the cost of gas and the overall efficiency of the system (i.e., the percentage of time gas was the incremental fuel, the type of gas plants used and the amount of baseload or intermittent generation available). This changes in very wet months, when hydro may be the marginal resource, or increasingly at midday on light-load days, when solar becomes a market driver. In Texas and the Plains states, wind is increasingly a market-driving resource. For utilities in the Midwest, South and East, the incremental fuel is typically a mix of gas-fired generation during peak and midpeak periods with coal-fired generation off-peak in some locations. Some utilities face much higher marginal costs or market prices in extreme winter weather because of gas price spikes, limits on gas availability, high peak loads and unreliability of service due to freezing of coal piles and some mechanical parts of power plants and gas wells.

In California and Nevada, utilities typically have modeled and averaged marginal energy costs over one or three years, corresponding to the length of time between rate cases, but PG&E uses six years. These very short-run energy analyses, particularly when coupled with long-run generation capacity cost analyses, tend to overstate the balance of costs for customer classes with lower load factors and understate them for customer classes with higher load factors. The cost of a combustion turbine, which is allocated heavily based on peak conditions, becomes a larger portion of marginal generation costs if short-run energy costs are lower than if higher longer-run costs are used.

It is of key importance that reasonable natural gas price forecasts are used, particularly if looking out beyond a very short time horizon. In much of the country, the modeling outputs are very sensitive to this input factor, and key results can vary greatly depending on the natural gas forecast. The E3 long-run incremental cost forecast uses short-term forecasts from futures and a longer-term mix of forecasts from the U.S. Energy Information Administration and the California Energy Commission's *Integrated Electric Policy Report* (Horii et al., 2016, pp. 5-8). Utilities tend to use their own forecasts, but in California those forecasts are updated after intervenor testimony is filed.

Greenhouse gas emissions are an important marginal cost, but there is not a consensus method to address it. Carbon cost is, in theory, internalized by California's cap-and-trade system, although it becomes difficult to properly model the dispatch in the Western United States when only California resources and California imports carry carbon values. The **Regional Greenhouse Gas Initiative** market performs a similar function in the Northeastern United States. In all jurisdictions where carbon prices are included, carbon prices must be forecast if longer-term marginal cost methods are used. Prices need to be forecast over the full study duration where markets do not exist for these products. Even in California and the Regional Greenhouse Gas Initiative states, market-determined allowance prices extend out for only a three-year period. However, in places where carbon is not explicitly valued, a marginal cost method should include current or future carbon values associated with fossil-fueled generation to provide forward-looking price signals. In jurisdictions covered by electric sector cap-and-trade programs, there are still questions about whether the marginal cost from the program is sufficient or whether another measure, such as the social cost of carbon or marginal cost of long-term greenhouse gas reductions, is more accurate.

The addition of renewable resources to utility portfolios, especially if added in advance of the need for capacity, depresses marginal energy costs by adding energy with zero fuel costs (or even negative costs in the case of wind energy with the production tax credit). The result is to reduce marginal costs in two ways. It reduces the heat rates of gas-fired generators on the margin. It also decreases the number of hours when a gas-fired resource is on the margin in some places where cheaper coal or surplus hydro (the Pacific Northwest or Canada) can be a marginal source of energy or when renewables are curtailed. In other words, the short-run model reduces energy costs relative to capacity costs when new renewable resources are constructed.

It can be argued that costs of compliance with an RPS are short-run marginal costs, in the sense that if load changes on a permanent basis, a portion of that load must be met with renewable resources. The capital and operating costs of those resources (possibly net of the fixed costs of an equivalent amount of peaking capacity) would replace the market prices and fuel costs from existing generation used to calculate marginal costs.[216] The Nevada utilities first developed calculations using the RPS as an adder to conventional resources in Sierra Pacific Power Co.'s 2010 rate case (Pollard, 2010).[217] The RPS adder was then adopted by California consumer groups (Marcus, 2010b, p. 45) and by Southern California Edison (2014, pp. 31-32). It is also included in the E3 long-run marginal cost model (Horii et al., pp. 36-38). Note that, mathematically, in the Western states that use marginal cost analysis, the RPS adder increases if short-run market energy prices decline (e.g., due to an update that reduces gas prices).

Before deregulation, there was a debate over whether short-run marginal energy costs should be the instantaneous cost in the given hour as envisioned in the original NERA method or should reflect other factors such as unit commitment. Often the actual unit that varies with short-term variation in loads is a flexible resource, not necessarily the least-cost resource, and the dispatch of hydro can change with changes in load. In California, the utilities commission adopted a method that computed marginal costs as the change in total costs for a large utility between a symmetrical increment of several hundred MWs above and several hundred MWs below current loads in each hour. This resulted in a more expansive definition of short-run marginal costs that included not just the incremental costs of a plant running in a given hour but the differences in how many power plants were committed if the load were different — thus causing changes in costs of startups and plants running at minimum load to be available the next day. These unit commitment costs generally increase the marginal costs experienced during peak hours above hourly marginal costs. In current wholesale markets, unit commitment costs tend to be reflected in day-ahead prices because bidders who need to commit a resource must include that cost in their bids.

Several ancillary services defined by FERC and ISOs/RTOs are purchased on an hourly basis. These include spinning reserves, nonspinning reserves available in a time frame of about 10 minutes, in some cases replacement reserves (plants that could fill another reserve type on a contingency basis if that reserve was used in real time) and frequency regulation (both upward and downward) on a minute-to-minute basis. Additionally, there are services that are not officially called ancillary services but that are related. These include the need to assure that enough generation is committed to meet energy requirements (residual unit commitment, acquired daily) and energy that can be dispatched to ramp upward or downward within a bid period to meet changes in demand and changes in variable (typically renewable) resource output that can be forecast hourly or subhourly (e.g., solar). Finally, there are out-of-market real-time costs necessary to maintain system reliability if generation is not available or if transmission contingencies occur. These costs are "uplift" (charged to system loads) by ISOs/RTOs. That said, uplift costs can be

216 As an analogy, in most jurisdictions with retail choice, RPS requirements typically are implemented in a way that is a short-run cost. As a percentage requirement based on load served or retail kWh sales, it automatically varies based on kWhs in a predictable way. Therefore, treating RPS requirements similarly in jurisdictions where generation is regulated is appropriate.

217 Those calculations established the principle, even though they were flawed because they included energy efficiency resources that were cheaper than market prices that could meet Nevada RPS requirements and because the energy efficiency costs did not consider a time value of money (Marcus, 2010c, pp. 7-8).

incurred unnecessarily if ISOs/RTOs fail to optimize existing markets to provide necessary reserves and other ancillary services to provide necessary grid support.

Although some utilities and industrial customers suggest these costs are really capacity costs and thus should be subsumed in the marginal cost of capacity, they are paid for in each hour along with market energy costs, so that, regardless of the semantics, they should be allocated on an hourly basis. The costs are not large in normally functioning markets. For purposes of evaluation of energy efficiency in California, E3 uses a figure of 0.7% of marginal energy costs for ancillary services (Horii et al., pp. 25-26),[218] a decrease from 1% several years ago. A more detailed study of California ISO ancillary services costs for the 12 months ending April 2010 ended up with 0.8% of marginal energy cost, with amounts ranging from 1.17% summer on-peak to 0.61% winter midpeak (Marcus, 2010b, p. 45). Although not large, the costs are real and should be included in a short-run energy costing methodology.

Costs paid on an hourly basis for intrahour ramping may also be incurred. This is particularly an issue in the Western U.S. The drop-off of solar energy as the sun sets plus increasing of loads toward an evening peak can cause a doubling of loads served by other resources (i.e., net loads, excluding wind and solar generation) on some low-load days in the spring and fall. This causes the need to rapidly ramp up conventional generation, such as natural gas and hydro, and opens up an important new role for storage. Any energy costs of ramp should be assigned as a marginal cost to those hours.

19.3 Short-Run Marginal Generation Capacity Costs

Under the short-run marginal cost method, the theory, as originally developed in the late 1970s, is that the value of generation capacity is capped at the least cost of acquiring generation for reliability. If all that was 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). Under this method, the cost of the peaker is multiplied by the real economic carrying charge, and O&M and A&G costs are added to it.

A number of technologies could be the least-cost generating capacity option, including:

- Conventional peaking generation, demand response or economic curtailment.
- Midrange generation net of fuel or market price savings.
- Short-term or intermediate-term power purchases.
- Results of RTO capacity market auctions or market prices for capacity procured for resource adequacy (if applicable).
- Centralized or distributed storage net of fuel or market price savings.

In equilibrium, without cheaper short-term options, the cost of a peaker would theoretically equal the shortage value customers experience from generation outages. That is the reason marginal generation costs have typically used a peaker, because they effectively assume equilibrium exists. The California and Nevada utilities other than PG&E use the full cost of a combustion turbine as the basis for marginal capacity costs. PG&E, the California Public Utilities Commission advocacy staff and other consumer intervenors recognize that the short-run marginal cost can be less than a peaker. Lower costs should occur if capacity is either unneeded or so economic that energy savings from construction of baseload generation exceeds the cost of the plant, or if cheaper options than a combustion turbine peaker are available. Theoretically, the marginal generation capacity cost can also be higher for short periods when there are shortages of capacity within the lead time of building generation, but those conditions have not occurred since the early 1980s (California Public Utilities Commission, 1983, pp. 220-222).

In 2017-2018, Southern California Edison claimed that some of the need for system reliability was not caused by peak loads but instead by the requirement to have adequate capacity available to ramp generation from midafternoon to the evening peak in periods of the year with relatively low loads (and relatively high output from conventional hydro plants that reduced their flexibility for use in peaking). Although many options are available to reduce the size and scope of the ramp, particularly storage and use of flexible

218 These costs do not include ramp, residual unit commitment or out-of-market costs.