Smart Rate Design for a Smart Future, Appendix A

Dividing the Pie: Cost Allocation, the First Step In the Rate Design Process[1]

By Jim Lazar

Introduction

Utility rate proceedings include distinct elements that together determine the utility's overall revenue requirements, the portion to be derived from each class, and the rates by which these will be recovered from individual consumers. These include:

Rate Base: Determining the fair value for rate-making purposes of the utility's investment in utility plant that is "used and useful"[2] in providing service to the public.

Operating Expenses: Determining the allowable level for operations and maintenance expenses, including labor, fuel, outside services, taxes, and other costs paid out by the utility.

Rate of Return: Ascertaining the allowed profit rate for shareholders, and the required interest rate for bondholders, together making up the "weighted cost of capital."

Cost Allocation: Dividing the revenue requirement among customer classes.

Rate Design: Calculating rates for each class of customers to produce the allocated revenue requirement based on assumed usage levels.

Other Elements: Many regulators make determinations on resource planning, low-income energy assistance, energy efficiency and renewable energy programs, and other elements of the overall utility function.

It is beyond the scope of this paper to address all aspects of utility rate-making; we are focused on the rate design element.[3] This paper does not address the determination of the revenue requirement (Rate Base, Operating Expenses, and Rate of Return). This chapter gives an abbreviated discussion of cost allocation only to provide an introduction to how these allocation elements and decisions made by regulators with respect to each element affect the eventual rate design.

The first step utilities and regulators follow in establishing retail prices to recover a given revenue requirement is a cost allocation analysis, usually called a "cost of service study" or COSS. There are many different methods used for computing a COSS, and no method is precise or "correct." Often regulators use the results of multiple studies, using different approaches to determine how the utility revenue requirement should be apportioned between customer classes. This chapter provides a brief overview of the different approaches used, and how the methodologies attempt to reflect utility costs in a causal manner.

1 This chapter is a greatly abbreviated version of a long paper on the issue of cost allocation prepared by author Jim Lazar for the Arizona Corporation Commission. See http://www.raponline.org/document/download/id/7765.

2 "Used and useful" is a regulatory concept—often triggered when a plant is first placed in service, but applicable throughout the life of the plant—for determining whether utility plant is eligible for inclusion in a utility's rate base. While different state courts have interpreted the concept differently, "used" generally means that the facility is actually operated to provide service, and "useful" means that without that facility service would either be more expensive or less reliable.

3 For an overall understanding of utility rate-making, see *Electricity Regulation in the United States: A Guide* at: http://www.raponline.org/document/download/id/645.

Frameworks: Marginal, Incremental, and Embedded Costs

There are three major philosophical approaches to cost allocation, known as “marginal” cost, “incremental” cost, and “embedded” cost. Each approaches cost and cost allocation in a fundamentally different manner, as shown in Table A-1.

Simply stated, “marginal cost” studies should look at the cost of building a new utility system, “incremental cost” studies look at the cost of augmenting an existing system, and “embedded cost” studies divide the actual recorded historical investments and current operating expenses between customer classes.

Because today’s utility systems typically consist of assets that were designed and built when costs and loads were significantly different than they are today, these three types of studies can produce significantly different results in the costs attributed to each customer class.

Methodologies: Demand/Energy vs. Time-of-Use Energy Weighted

Prior to the advent of economical advanced metering, utilities had to estimate the contribution of each customer class to peak demands and used samples of customers to measure this. Because the usage of each class by hour of the day, day of the week, and month of the year could only be estimated, utilities used shortcut methods to determine how much of the cost of baseload, intermediate, and peaking resources should be apportioned to each customer class.

Embedded cost studies done in that era classified assets simply as “demand-related,” “energy-related,” and “customer-related.” The demand-related costs – including much of the capital costs for generation and transmission assets – were allocated among customer classes based on the estimated class contribution to peak demand. The high capital costs for nuclear, hydro, and coal plants were often

Table A-1

Approaches to Cost Allocation

Function	Long-Run Marginal Cost	Incremental Cost	Embedded Cost
Production (generation and purchased power)	Cost of constructing and operating an optimal mix of new generating facilities at today’s costs to serve the current customer requirements.	Cost of adding additional generating facilities at today’s cost to serve incremental changes in usage by customers.	Booked actual investment and operating expense for existing generating resources used to serve customers during the test year.
Transmission	Cost of constructing and operating an optimal transmission system at today’s prices to serve current customer requirements.	Cost of augmenting existing transmission to serve expected changes in customer requirements.	Actual cost of existing transmission resources used to serve customer requirements.
Distribution	Cost of constructing and operating a new optimal distribution system to serve current customer requirements.	Incremental cost of augmenting the current existing distribution system to serve changes in customer requirements.	Actual cost of existing distribution system currently used to serve customer requirements.
Administrative Costs	Cost of an optimal administrative framework to support an optimal utility system.	Changes in the cost of administrating the utility as customer requirements change.	Actual costs incurred in the test year to provide administrative functions of the utility.
Fuel Costs	Fuel costs that would be incurred if the utility generating resources were optimized to current requirements.	Changes in fuel costs incurred in response to changes in customer usage.	Actual fuel costs incurred in the test period for existing generating resources.
Taxes	Taxes that would be incurred if the utility’s production, transmission, and distribution system were optimized to current customer requirements.	Incremental taxes that would be incurred in response to changes in customer usage.	Actual taxes paid by the utility in the test year.

treated no differently than low capital costs for peaking units. That measure of peak demand could be as narrow as the highest single hour of the year (1CP), the average of the four summer monthly peaks (4CP), the average of twelve monthly system peak hours (12CP) or, more broadly, as the highest 100 or 200 hours of system demand. Fuel costs in the past were simply allocated based on total kilowatt-hour usage, mixing free fuel for hydro units, low-cost coal, and nuclear fuel, and high cost oil or natural gas used in peaking resources. This approach became widely recognized as inappropriate when very high capital cost nuclear units were built, and when demand response programs emerged as alternatives to generation and transmission capacity to meet narrow periods of peak demand.

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

Within the marginal cost and incremental cost categories, most treat the cost of peaking capacity as only that of a peaking resource, such as a combustion turbine or demand response measure, not the capital costs of baseload generating resources.

The point is that no single method for allocating production and transmission costs between classes is appropriate for every resource and for every utility. Regulators often consider multiple studies and adopt a blended cost allocation method considering the different results presented.

Demand-Related Costs

The term "demand-related cost" is an artifact of the era when utilities did not have precise data on the use of each customer or customer class at different hours of the day. This term was often applied to either all capital and operating costs of all generation, transmission, and shared distribution plant, or else to that portion determined necessary to meet peak demand.

The Problem with Non-Coincident Demand Billing

A donut shop uses power in the morning, and an adjacent nightclub uses power in the evening. With non-coincident demand billing, they both pay a demand charge based on their individual maximum usage, even though they can share the same capacity.

Across the street, a 24-hour diner uses power continuously. Even though its usage at the time of the system peak demand may be identical to the combined peak period usage of the donut shop and nightclub, it pays only half as much in demand charges as the combined loads for the donut shop and nightclub, because all of the power flows through one meter.

Non-coincident demand measurement simply favors those customers with diversity on their side of the meter.

These demand-related costs would then be allocated based on one or more measures of coincident peak demand (system peak), class peak demand (highest load of each class, whenever it occurs) or non-coincident peak demand (sum of the individual maximum demands of customers, whenever they occur).

For large commercial and industrial customers, these costs were often converted into "demand charges" in the rate design – applied on a $/kW basis to the non-coincident demand of each customer in the class on a monthly basis.

The problem with non-coincident demand measurement is that it fails to recognize the different times of the day and of the year when individual customer demands occur. Because of this, it may fail to accurately reflect the impact of customers on utility system costs.

In more sophisticated studies that can be done today with more detailed usage data from individual customer smart meters and from metering of each distribution circuit, it is now possible to apply most of these costs that are not customer-specific to time-varying energy rates, so that users of shared facilities share appropriately in the cost of these facilities. While billing customers for coincident peak demand is preferable to using their non-coincident demand, costs in excess of what would be incurred to achieve demand response during the key hours are better reflected in time-varying energy prices.

Energy-Related Costs

In the early years of cost allocation studies, before the costs of different types of facilities became as divergent as they are today, the only costs treated as energy-related were typically fuel and variable purchased power costs. These were typically allocated to each customer class based on (loss-adjusted) kilowatt-hour sales. Today, many regulators consider the majority of the investment in baseload resources to be energy-related costs.

Many regulators have come to realize that the fuel costs for baseload and peaking resources are very different, and should be apportioned to the periods when each type of resource is used. Just as the capital costs of baseload resources are assigned to all hours and the capital costs of peaking resources are assigned to the on-peak hours, it is now common for the fuel and variable operating costs of different types of resources to be assigned to the hours when those are used.

Distribution Costs

Distribution costs are among the most controversial elements of utility cost allocation studies addressed by regulators. These are mostly shared facilities, and they serve baseload usage and peak usage and are needed for individual customers to obtain service at all. There are many different cost-allocation approaches used. The text box below describes the theories applied in three of the most commonly used methodologies.

Each of these approaches has been applied by one or more regulator over time. However, we draw attention to some key guidance from two of the pioneer authors in the field of utility rate-making as to how these costs should be treated. In general, these tend to favor the "basic customer" or "peak and average" approaches, and to ensure that some system capacity costs are allocated to every hour of the year, not just to peak periods.

Table A-2

Different Approaches to Distribution System Classification and Allocation

Function	Minimum System or Zero-Intercept	Basic Customer	Peak and Average
Description	Cost of a minimum sized distribution system is treated as customer-related. Other costs treated as demand-related.	Only customer-specific costs are treated as customer-related. Other costs are treated as demand-related.	Cost of a basic distribution infrastructure treated as energy related; cost of overbuilding attributed to demand.
Substations	Allocated on the basis of class contribution to peak demand.	Allocated on the basis of class contribution to peak demand.	Allocated partly based on class peak demand, partly on kWh usage.
Poles and Wires	Percentage that would be incurred to build a hypothetical minimum-size system allocated on a per-customer basis; balance allocated based on peak demand.	Allocated on the basis of class contribution to peak demand.	Allocated partly based on class peak demand, partly on kWh usage.
Transformers	Cost of a small (~10 kVA) transformer allocated per-customer; balance allocated based on peak demand of customers at distribution voltage.	Allocated on the basis of class contribution to peak demand at the distribution voltage level.	Allocated partly based on class peak demand, partly on kWh usage for customers taking service at distribution voltage level.
Dumb Meters	Per-Customer	Per-Customer	Per-Customer
Smart Meters	Customer / Energy / Demand	Customer / Energy / Demand	Customer / Energy / Demand

Table A-3

Rate-Making Textbook Discussion of Distribution Infrastructure Costs

Bonbright (1961)[4]	Garfield and Lovejoy (1964)[5]
"While, for the reason just suggested, the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to me clearly indefensible, its exclusion from the demand-related costs stands on much firmer ground. But, if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason previously stated, to which cost function does it then belong? The only defensible answer, in my opinion, is that it belongs to none of them. Instead it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But the fully distributed cost analyst dare not avail himself of this solution, since he is the prisoner of his own assumption that "the sum of the parts equals the whole." He is therefore under impelling pressure to "fudge" his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other cost categories.	*(1) All utility customers should contribute to capacity costs.* *(2) The longer the period of time that a particular service pre-empts the use of capacity, the greater should be the amount of capacity costs allocated to that service.* . . . *(4) The allocation of capacity costs should change gradually with changes in the pattern of sales as the market develops. As noted previously, the original Peak Responsibility Method is prone to produce erratic results with changes in the timing of system peaks.* . . . *(6) More demand costs should be allocated to a unit of capacity pre-empted during a peak period than to one pre-empted off-peak.*

Customer Costs

The term "customer costs" refers to those costs properly allocated between classes of customers on the basis of number of customers. As discussed above, this involves a highly controversial element of cost allocation, with some analysts (generally working for industrial customers or electric utilities) advocating that more costs be classified as customer-related, while other analysts (generally working for regulatory commissions, consumer advocates, and low-income intervenors) advocating a very narrow definition of customer costs.

The controversy arises over the issue of what costs are added if the number of customers rises. In an illustrative example, if an owner of a single-family residence converts a portion of his/her home into an accessory dwelling unit (mother-in-law apartment), the utility needs to install a second meter, render a second bill, and process a second payment. These are costs that increase (or decrease) as the number of customers served goes up or down. These costs form the customer-related costs generally used in the Basic Customer and Peak and Average cost allocation methodologies widely used throughout the United States. As the Washington Utilities and Transportation Commission stated in two rate cases in the 1980s:

> *In this case, the only directive the Commission will give regarding future cost of service studies is to repeat its rejection of the inclusion of the costs of a minimum-sized distribution system among customer-related costs. As the Commission stated in previous orders, the minimum system method is likely to lead to the double allocation of costs to residential customers and over-allocation of costs to low-use customers. Costs such as meter reading, billing, the cost of meters and service drops, are properly attributable to the marginal cost of serving a single customer. The cost of a minimum-sized system is not. The parties should not use the minimum system approach in future studies.*[6]

4 Bonbright, *Principles of Public Utility Rates,* 1961, p. 348.

5 Garfield and Lovejoy, *Public Utility Economics,* p. 163.

6 Washington Utilities and Transportation Commission v. Puget Sound Power and Light Company, Cause U-89-2688-T, Third Supp. Order, p. 71.

And:

The Commission finds that the Basic Customer method represents a reasonable approach. This method should be used to analyze distribution costs, regardless of the presence or absence of a decoupling mechanism. We agree with Commission Staff that proponents of the Minimum System approach have once again failed to answer criticisms that have led us to reject this approach in the past. We direct the parties not to propose the Minimum System approach in the future unless technological changes in the utility industry emerge, justifying revised proposals.[7]

There has been general agreement among analysts that billing and collection costs are customer-related costs, but the emergence of smart meters has created a new controversy over whether meters (smart meters) should be considered customer-related costs. These are installed one-per customer, but the purpose of deployment is to enable time-varying rates, to enable demand response programs, and to enable critical peak pricing schemes. The incremental costs of smart meters are arguably related to peak demand and energy as much as to a per-customer purpose. We discuss this at length in Appendix D ("The Specter of Straight Fixed/Variable Rate Designs and the Exercise of Monopoly Power").

Opinion as to whether distribution infrastructure costs (poles, conductors, transformers, and meters) are treated as customer-related in a COSS often drives the positions that parties take in the rate design phase of rate cases. Parties that advocate customer classification of the distribution infrastructure often use that perspective to advocate high monthly customer charges, in some cases as high as $25/month. Parties that advocate a narrow definition of customer costs generally advocate monthly customer charges that reflect the cost of billing and collection, in the range of $5-$10/month. For a variety of reasons, most state utility regulators have adopted a relatively narrow position on what costs should be included in the customer charge.

Treatment of Basic Infrastructure, Administrative, and Other Unallocable Costs

The costs that remain include those of the utility's underlying infrastructure, plus administrative costs and other costs that are not directly related to peak demand, to energy volumes, or to the number of customers. These include, at a minimum, the administrative and general costs of the utility, the general office facilities, and the costs of regulation.

Most cost studies apply these costs as applicable to all of the allocated costs. In embedded cost studies, they are allocated to various subtotals of production, transmission, and distribution costs. In marginal cost studies, they are often treated as adders to the annual capital carrying cost (return, depreciation, and associated taxes) applied to calculate marginal customer cost, demand cost, and time-varying energy costs.

Table A-4

Hypothetical Revenue-to-Cost Ratio and Return Index

Row	Cost Element	Formula	Class 1	Class 2	Class 3	Total
1	Operating Income	Assume	$1,000	$1,000	$1,000	$3,000
2	Rate Base	Assume	$10,000	$13,000	$7,000	$30,000
3	Return on Rate Base	(1)/(2)	10.0%	7.7%	14.3%	10.0%
4	Equal Return Operating Income	(3) Avg x (2)	$1,000	$1,300	$700	$3,000
5	O&M Expense Allocation	Assume	$3,000	$3,500	$4,000	$10,500
6	Current Revenue	(1) + (5)	$4,000	$4,500	$5,000	$13,500
7	Equal Return Revenue (Equal Return Operating Income + Equal Return)	(4) + (5)	$4,000	$4,800	$4,700	$13,500
8	Return Index (Class Return/System Return)	(3) / (3) Avg	100%	77%	143%	100%
9	Revenue-to-Cost Ratio (Ratio of Current Revenues to Equal Return Revenues)	(6) / (7)	100%	94%	106%	100%

7 Washington Utilities and Transportation Commission v. Puget Sound Power and Light Company, Docket No. UE-920499, Ninth Supp. Order on Rate Design, p. 11.

Presentation of Study Results

The "results" of a cost allocation study are usually presented in the context of showing that some classes of customers are paying more or less than their share of costs. The two approaches commonly used are a "revenue to cost ratio" and a "return index." The "revenue to cost ratio" compares the customer class actual revenue to the regulator-determined class share of revenue responsibility, and can be done with either embedded cost study or marginal/incremental cost study results, while the return index is strictly an embedded cost study concept. The two can produce quite different results because the return index is much more sensitive to deviations from the target revenue. Table A-4 provides an example of these two comparisons based on an illustrative embedded COSS.

The variation in the "return index," from 77% to 143%, could be used to show that Class 2 is seriously "underpaying." But if the revenue-to-cost ratio is used, this class is shown as paying 94% of their allocated revenue requirement, typically within the "range of reasonableness" used by regulators to determine if a disproportionate rate adjustment should be applied to a particular class.

Unit Costs

The most important results of a COSS for rate design purposes is the "unit cost" calculations that result. The "cost of service" is divided between "customer-related," "demand-related," and "energy-related costs." These are sometimes used as guides for rate design; however, it is not uncommon for regulators to use embedded cost studies for allocating costs between classes, and marginal cost concepts for designing rates within classes.

Table A-5 shows illustrative results of a COSS in terms of unit costs.

Summary

There are as many different methods for allocating costs as there are analysts performing cost allocation studies. The results presented by a utility, using one methodology, may be dramatically different from the results of studies prepared for industrial customer advocates, consumer advocates, or low-income advocates. Regulators routinely consider the results of multiple studies in determining a cost allocation and rate design that meets the legal test of "fair, just, and reasonable." The illustrative results shown in this chapter are only that—not intended as "fair" values for any utility system or to be a portrayal of anything but the differences that may be presented.

Table A-5

Hypothetical Cost Allocation and Unit Cost Calculation

Row	Cost Element	Formula	Class 1	Class 2	Class 3	Total
10	Demand-Related Costs at Equal Return	Assume	$1,000	$1,000	$1,200	$3,200
11	Energy-Related Costs at Equal Return	Assume	$2,000	$3,000	$3,200	$8,200
12	Customer-Related Costs at Equal Return	Assume	$1,000	$800	$300	$2,100
13	Total Cost of Service	(10) : (12)	$4,000	$4,800	$4,700	$13,500
	Billing Determinants					
14	Demand	Assume	Not Metered	200	200	
15	Energy	Assume	30,000	40,000	45,000	
16	Customer (Bills/Year)	Assume	500	100	20	
	Unit Costs					
17	Demand $/kW/Month	(10) / (14)		$5.00	$6.00	
18	Energy $/kWh	(11) / (15)	$0.100	$0.075	$0.071	
19	Customer $/Customer/Month	(12) / (16)	$2.00	$8.00	$15.00	

The Regulatory Assistance Project (RAP)®
Beijing, China • Berlin, Germany • Brussels, Belgium • **Montpelier, Vermont USA** • New Delhi, India
50 State Street, Suite 3 • Montpelier, VT 05602 • *phone:* +1 802-223-8199 • *fax:* +1 802-223-8172
www.raponline.org