

**CHARGING FOR DISTRIBUTION UTILITY**  
**SERVICES:**  
**ISSUES IN RATE DESIGN**

December 2000

Frederick Weston

with assistance from:

Cheryl Harrington

David Moskowitz

Wayne Shirley

Richard Cowart

The Regulatory Assistance Project  
16 State Street, Montpelier, VT 05602

Phone: 802-223-8199

Fax: 802-223-8172

rapvermont@aol.com

#### IV. THE COSTS OF DISTRIBUTION SERVICES

A first question to be answered when designing rates is what does it cost to provide the service? What are the causes and magnitudes of the relevant costs? It is helpful to observe that the costs recovered by distribution-level rates have historically extended far beyond the distribution system. Are there other costs, not directly related to distribution services, that distribution rates are expected to recover? What follow here are an overview of utility costing methodologies and a discussion of some practical considerations to keep in mind when determining rate structures.

##### A. Utility Plant Costing Methods

Utilities and regulatory commissions use a variety of methods for determining and allocating cost responsibility among customers and customer classes. There are two general types of cost study, embedded and marginal. Embedded, or fully distributed, seeks to identify and assign the historical, or accounting, costs that make up a utility's revenue requirement. Marginal, as the name connotes, aims at determining the change in total costs imposed on the system by a change in output (whether measured by kilowatt-hour, kilowatt, customer, customer group, or other relevant cost driver). Each commission around the country uses these studies in its own way to inform the rate design process; in the end, most commissions rely on embedded cost studies for ultimate allocations and price levels, constrained as they are by a legal requirement to set rates that offer the prudent utility a reasonable opportunity to earn a fair rate of return on its assets used in service to public.<sup>33</sup> The allocations, however, are often structured to reflect at least relative differences in the marginal costs of providing a company's various services.

##### 1. Cost Causation

There is broad agreement in the literature that distribution investment is causally related to peak demand. Numbers of customers on the system and energy needs are also seen to drive costs, but there is less of a consensus on these points or on their implications for rate design. In addition, not all jurisdictions employ the same methods for analyzing the various cost components, and there is of course a wide range of views on their nature—marginal, embedded, fixed, variable, joint, common,<sup>34</sup> etc.—and thus on how they should be recovered in rates.

---

33. NARUC, p. 32.

34. The costs of multiple products or services supplied by the same plant or process are either common or joint. Common are those that generally do not vary with changes in output. The classic example is the president's desk, which is needed to run the firm as a whole but is incremental to the provision of no particular good or service. Another example is that of an airline flight, the majority of whose costs are incurred in a single lump and do not vary with the number of passengers carried. Put another way, common costs are those for which the unit of production (the single flight), which is the basis of cost incurrence, is larger than the unit of sale (a

(continued...)

Numbers of customers, usage, and demand, however, are only part of the story. Other factors also play an important role: geography (particularly population density), system design (e.g., aerial versus underground lines), and the utility's business practices (for example, the extent of expenditures on billing, answering customers' questions/complaints, etc.). The implications of such factors on rate design is unclear, however: one can charge for services on the basis of numbers of customers, usage, and demand, but not on the basis of other such factors.<sup>35</sup>

## 2. Embedded Costs

### a. Cost Classification: Customers, Demand, and Energy

Traditionally, customer costs are those that are seen to vary with the number of customers on the system: service drops (the line from the distribution radial to the home or business), meters, and billing and collection. Some utilities and jurisdictions also include some portion of the primary and secondary distribution plant (poles, wires, and transformers) in these costs, on the ground that they also are driven more by numbers of customers than by demand or energy. Similar reasoning leads to the designation of the costs of customer service and customer premises equipment as customer-related. But, since the system and its components are sized to serve a maximum level of anticipated demand, the notion that there are any customer costs (aside from perhaps metering and billing) that are not more properly categorized as demand can be challenged (see Subsections 3 and 4, below).

Utilities classify significant portions of their embedded distribution investment as demand-related, reasoning that it is designed and installed to serve a customer or group of customers according to their contribution to some peak load (system, substation, etc.). Substations are a typical example of such costs, but so too may be a significant portion of the wires and related facilities, since they are sized, at least in part, to serve a peak demand.

There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states. A

---

34. (...continued)  
single ticket to a single passenger). Kahn, Vol. I, p. 77. If services produced in common can be produced in varying proportions, it may then be possible to identify separate marginal production costs for each.

Products that are produced in fixed proportions (e.g., cotton fiber and cottonseed oil, beef and hides, mutton and wool) are characterized by joint costs. For that aspect of their production process that is joint, the products have no separately identifiable marginal costs. *Id.*, p. 79. See also Bonbright, pp. 355-360.

35. These other cost factors can have huge effects on prices. Three distribution utilities in the American south, owned by the same holding company and using the same costing methodology, recently proposed new metering, customer service rates, and delivery rates. The rates, designed as a combination of monthly per-customer and per-kW of peak demand charges, vary from company to company by ratios ranging from 1.25 to 1.9.

variation is to treat poles, wires, and transformers as energy-related driven by kilowatt-hour sales but, though it has obvious appeal, only a small number of jurisdictions have gone this route.

Two other approaches sometimes used are the minimum size and zero-intercept methods. The minimum size method operates, as its name implies, on the assumption that there is a minimum-size distribution system capable of serving customers minimum requirements. The costs of this hypothetical system are, so the argument goes, driven not by customer demand but rather by numbers of customers, and therefore they are considered customer costs. The demand-related cost portion then is the difference between total distribution investment and the customer-related costs. The zero-intercept approach is a variation on the minimum size. Here the idea is to identify that portion of plant that is necessary to give customers access but which is incapable of serving any level of demand. The logic is that the costs of this system, because it can serve no demand and thus is not demand-related, are necessarily customer-related.<sup>36</sup> However, the distinction between customer and demand costs is not always clear, insofar as the number of customers on a system (or particular area of a system) will have impacts on the total demand on the system, to the extent that their demand is coincident with the relevant peak (system, areal, substation, etc.).

Any approach to classifying costs has virtues and vices. The first potential pitfall lies in the assumptions, explicit and implicit, that a method is built upon. In the basic customer method, it is the *a priori* classification of expenditures (which may or may not be reasonable). In the case of the minimum-size and zero-intercept methods, the threshold assumption is that there is some portion of the system whose costs are unrelated to demand (or to energy for that matter). From one perspective, this notion has a certain intuitive appeal these are the lowest costs that must be incurred before any or some minimal amount of power can be delivered but from another viewpoint it seems absurd, since in the absence of any demand no such system would be built at all. Moreover, firms in competitive markets do not indeed, can not price their products according to such methods: they recover their costs through the sale of goods and services, not merely by charging for the ability to consume, or access.

Other assumptions are of a more technical nature. What constitutes the minimum system? What are the proper types of equipment to be modeled? What cost data are applicable (historical, current installations, etc.)? Doesn't the minimum system in fact include demand costs, since such a system can serve some amount of demand? The zero-intercept method attempts to model a system that has no demand-serving capability whatsoever, but what remains is not necessarily a system whose costs are driven any more by the number of customers than it is by geographical considerations, whose causative properties are neither squarely demand- nor customer-related. Does use of an abstract minimum system place a disproportionate share of the cost burden on

---

36. It is called zero-intercept because it relates installed cost to current carrying capacity or demand rating, creat[ing] a curve for various sizes of the equipment involved, using regression techniques, and extend[ing] the curve to a no-load intercept. NARUC, p. 92.

certain customers or classes, in certain cases even resulting in double-counting? The answers chosen to these and other questions will have impacts upon the respective assignments (by type and customer class) of costs.<sup>37</sup>

Historically, the investment decisions of system planners in vertically-integrated utilities were constrained by the least total cost objective: simply, that they would make that combination of investments that were expected, given their assessments of risk, to meet expected demand for service over some reasonable planning horizon. Given the inability to store electricity and the typical obligation to serve all customers *on demand*, a utility was required to have sufficient capacity available to meet peak demand. And, if its only obligation were to meet peak demand, then it would install only the most inexpensive capacity. However, it had also to serve energy needs at other times, and it is a general characteristic of electric generation technology that as capacity costs decrease variable operating costs increase. There is, therefore, a trade-off between capacity and energy costs that system planners considered when building (or purchasing) new capacity, if they hoped to minimize total costs. Put another way, significant portions of generating capacity were purchased not to meet demand, but to serve energy, when the fuel cost savings that the more expensive generation would produce were greater than the additional costs of that capacity. These incremental capacity costs were therefore correctly viewed as energy costs.

A similar kind of analysis can inform the design of distribution systems, as it also does transmission. The question is whether there is some amount of capacity in excess of the minimum needed to meet peak demand that can cost-effectively be installed. The additional capacity larger substations, conductors, transformers will reduce energy losses; if the cost of energy saved is greater than that of the additional capacity, then the investment will be cost-effective and should be made.<sup>38</sup> For the purposes of cost analysis and rate design, these kinds of distribution investments are rightly treated as energy-related.<sup>39</sup>

#### b. Cost Allocation

As a general matter, distribution facilities are designed and operated to serve localized area loads. Substations are designed to meet the maximum expected load of the distribution feeders radiating from them. The feeders are designed to meet at least the maximum expected loads at the primary

---

37. Sterzinger, George, The Customer Charge and Problems of Double Allocation of Costs, *Public Utilities Fortnightly*, July 2, 1981, p. 31; see also Bonbright, p. 347-348.

38. Losses vary with the square of the load. We note also that there is some minimum amount of losses that cannot be avoided, and that conductors must be sized such that the losses can be absorbed while still meeting peak load. To this degree, losses impose a capacity, rather than energy, cost.

39. An unhappy consequence of separating distribution and transmission planning from that of generation in restructured markets is the potential loss of this capacity-versus-energy consideration when making new investment. Certainly, without some sort of regulatory or legislative requirement, wires-only companies have no generation cost-savings motive to guide their planning decisions.

and secondary service levels. (As noted above, some investment in distribution capacity may be seen as reducing energy losses rather than serving peak demand.) For costing purposes it is the relevant subsystem's (substation, feeder, etc.) peak that matters, but these peaks may or may not be coincident with each other or with the overall system's peak. There can be significant variation among them. Consequently, one practice is to allocate the costs of substations and primary feeders (which usually enjoy relatively high load factors) to customer class non-coincident peaks and to allocate secondary feeders and line transformers (with lower load factors) to the individual customer's maximum demand.<sup>40</sup> In addition, costs are allocated according to voltage level; customers taking service at higher levels are typically not assigned any of the costs of the lower-voltage systems that do not serve them. Costs are then allocated among customer rate groups (or classes) which requires, among other things, information and judgments about coincidence of demand when customers of different classes share facilities, as is often the case.

### 3. Marginal Costs

For the reasons stated earlier, it is the long-run marginal cost that is most relevant to designing rates. It can be described as the cost of that lumpy, geographically dispersed set of investments that a utility must make if demand continues to grow after the distribution system has initially been built out.

#### a. Demand and Energy

As already noted, the drivers of distribution costs are typically seen to be peak demand (itself driven by both customer demand and numbers of customers) and energy needs.<sup>41</sup> For the purposes of marginal cost analysis, it is also necessary to identify investments that are not made to serve incremental demands, but are made for some other purpose—reliability, replacement of existing systems, etc. The costs of these investments are generally not included in marginal cost calculations, although, in certain cases, there may be legitimate arguments to the contrary.<sup>42</sup>

---

40. Class non-coincident peak may not be the best measure of cost causation, since much of the system serves a variety of customer classes. Chernick, Paul, *From Here to Efficiency: Securing Demand-Management Resources*, Vol. 5, 1993, p. 81. Ideally, the object is to design rates that reflect the costs of customers' contributions to the relevant peak.

41. It is worth noting that, in the short run, distribution costs vary more closely with numbers of customers than with load (except in capacity-constrained areas). For rate design, with its focus on the long run, this fact need not be a distraction. It does, however, have implications for setting revenue requirements. We address this question in Chapter V, below.

42. For instance, at the time that an investment to replace existing facilities (whose loads, let us say, are not expected to change over some extended period) is being contemplated, there are costs that can potentially be avoided. In the extreme, replacement would be unnecessary if all customers served by the facility were to decide to go off-grid. Other, more likely alternatives involve combinations of end-use efficiency, distributed generation, and smaller, more efficient distribution technologies. On these bases, the marginal or, more reasonably, the larger  
(continued...)

Many of the same cost classification and assignment questions that pervade embedded cost analyses also recur in marginal cost studies, although their answers have different analytical effects. Whereas an embedded cost study strives to identify and assign total historical costs to classes of service (on the basis of any of a number of principles, including cost causation and fairness), a marginal cost analysis aims to determine the cost consequences of changes in output and thus the value of resources that must be used to serve incremental demand. Therefore, costs that are unaffected by changes in output (which describes all common and many joint costs) are excluded from the costs under examination.<sup>43</sup>

The study period for a marginal cost analysis is forward-looking and should be of sufficient duration to assure that all incremental demand is related to the investments forecast to serve that demand: a mismatch of timing and investment could result in significantly over- or understated costs. Those incremental costs are then discounted to their present value and annualized over the planning horizon. This has the effect of smoothing out the lumpiness of investment in relation to changes in demand.<sup>44</sup> This analysis relates changes in total costs to changes in demand (aggregating demand increases caused by the addition of customers with those caused by increases in demand per customer).<sup>45</sup> Since new customers create additional demand, this approach is not unreasonable.

Even so, some jurisdictions consider certain costs customer-related and treat them separately for the purpose of marginal cost analysis. Customer premises equipment that which is dedicated specifically to individual customers and unrelated to variations in demand (meters and perhaps service drops) are probably the only distribution costs that can be directly assigned to customers (except in the cases of customers who have additional facilities transformers, wires, even

---

42. (...continued)

incremental costs of distribution can be calculated. If replacement of the particular component of the system is forecast for some time in the future, then its expected future costs would need to be discounted appropriately to yield a present-value incremental cost.

43. Because marginal cost is defined as the change in total cost arising from a change in output, all costs are, strictly speaking, included in the analysis. It just happens that most are netted out, to reveal those that are caused by the change in output. As a practical matter, however, an analyst may simply identify the costs that vary with output and exclude the rest. It is this second approach, however, that raises debates about the nature of costs and whether they should be included in the analysis. Are they joint or common? Do they vary with demand, energy, customers, or not at all? Resolving the issues usually requires large doses of judgment.

44. An alternative approach is to calculate the cost (savings) of advancing (deferring) by one year the planned stream of investments to meet the increment (decrement) in demand. This approach yields a cost that is equal to the value of the marginal investments for one year (which is the same as the economic carrying charge on those investments). This method is often used, for example, to determine an annual cost per kW of generating capacity.

45. For sizing much of the distribution system, demand is the critical factor. One customer contributing six kilowatts to peak demand has the same impact as two each contributing three kilowatts.

substations, dedicated solely to their needs).<sup>46</sup> Some jurisdictions also consider other facilities (line transformers, secondary level conductors) in some measure customer-related, but, to the extent that they are jointly-used to serve more than one customer, it may be difficult to establish that the addition or loss of any one customer will affect the costs of those facilities.<sup>47</sup> In any event, if some costs are deemed marginal customer costs (which means that they are avoidable only at the time of hook-up), it by no means follows that they should be recovered in recurring monthly fixed fees (see Section V.A.5., below).

Other approaches sometimes used to resolve the cost-causation question are the minimum system and zero intercept methods. Here, instead of using embedded cost data, the distribution system is modeled to determine the cost (in current dollars) of a hypothetical system that could serve all customers minimum demand or (in the case of zero-intercept) that could provide voltage but not power.<sup>48</sup> This cost would be deemed customer-related and separated from the total incremental cost previously determined, to identify the demand (or, more properly, the demand- and energy-related) portion. For the reasons stated earlier, we challenge the wisdom of these approaches.<sup>49</sup>

Other methodological difficulties may also arise. By definition, joint and common costs are not marginal, but occasionally they creep into the analysis, when, for example, they make use of what are in effect *average*, not *marginal*, investments and expenditures.<sup>50</sup> And, as with embedded costs, marginal costs are typically broken out by customer class. Here, again, the analysis requires

---

46. After the meter, the customer service drop is typically seen as the least demand-related component of the system: it is sized to exceed any realistic maximum demand that the consumer might impose and it will last a very long time. However, although it is true that no investment would be made unless a customer were present, it is also true that the amount of the initial investment increases as the customer's forecasted load increases. Thus, customer investments can be seen as demand-related, as can investments farther up the system transformers, wires, and substations whose sizing depends on expected peak demand. Bouford, James D., *Standardized Component Method for the Determination of Marginal and Avoided Demand Cost at the Distribution Level*, Central Maine Power Company, (unpublished and undated), pp. 3-4.

47. NARUC, p. 136.

48. A handbook published by the National Economic Research Associates (NERA), which is often cited in support of the minimum system distribution cost classification, states that only the labor costs necessary to put together a minimum system and no conductor and transformer costs are customer-related. NERA, *How To Quantify Marginal Costs: Topic 4*, (prepared for the Electric Utility Rate Design Study, March 10, 1977), pp. 76.

49. California, for instance, has rejected the minimum system approach to marginal costs, favoring instead a method which uses the weighted average of the costs of continuing to serve existing customers and the costs of initiating service to new customers.

50. See, e.g., NARUC, p. 127, which notes that, because calculating marginal distribution and customer costs can be difficult, it is still common for analysts to use some variation of a projected embedded methodology for these elements, rather than a strictly marginal approach. This tack is justified by the sweeping assumption that projected embedded distribution costs are a reasonable approximation of marginal costs. The assumption is, however, contestable. FERC accounting requirements, which form the basis of most embedded cost analyses, include in distribution certain, and often substantial, administrative and general (A&G) costs (Accounts 920 to 935). A&G is not caused by the provision of distribution service.



## CHARGING FOR DISTRIBUTION UTILITY SERVICES

PAGE 35

reasonable assessments of the coincidence of demand, when customers of different classes share facilities.

Another dimension of cost, and perhaps most revealing, is the geographic. There are several aspects to it. First are the topographical and meteorological characteristics of the area over which the distribution system is laid. Elevations, plant life, weather, soil conditions, and so on all have effects on costs. So too demography, which is captured partly by demand and numbers of customers, but also affecting costs is the density of customers in an area (sometimes expressed as customers per mile). These influences combine in assorted ways, with themselves but also with changes in load and rates of investment, to produce variations in costs from one area of the distribution system to another. It is not unusual to see marginal distribution costs varying greatly from one place to another, even when the distances between the different areas is comparatively short. Table 1 describes the significant variations in costs for incremental distribution investments in a large mid-western utility.

	Average System Marginal Costs per kW	Area Specific High-Low Marginal Costs per kW	Annual Cost @ 15% Capital Cost Recovery Factor	Average Marginal Costs per kWh @ 20% Load Factor <sup>51</sup>	High Marginal Costs per kWh @ 20% Load Factor
Transmission	\$230	NA	\$34	\$0.02	\$0.04
Distribution Lines	\$960	\$1,575 - 0	\$140	\$0.08	\$0.135
Distribution Transformers	\$60	\$300 - 0	\$9	\$0.0015	\$0.025
Total	\$1,250	\$1,875 - 0	\$183	\$0.1015	\$0.20

Table 1

Differentiating marginal costs along these lines will tell a utility where investment (whether in new facilities, end-use efficiency, or distributed generation) is needed and what the minimum value of that investment is. Whether for rate-making purposes this information is useful should distribution rates be geographically deaveraged? is a tougher question. We take it up in Chapter V, below.

51. This is estimated load factor for the incremental distribution investment alone, not for the entire distribution system altogether. Incremental investment to meet peak needs typically manifests low load factors; 20% is a conservatively high estimate.

#### 4. Key Concern in Determining Costs: Follow the Money

The occasionally technical and arcane matters taken up in embedded and marginal cost studies are, of course, important, but it is perhaps more important to bear in mind that, in rate design cases, what is fundamentally at issue is who should bear what revenue responsibilities. In the interplay between cost allocation and rate structures, the debate over money is played out. First is the question of what costs will be categorized as *distribution*, as opposed to transmission or generation in the case of vertically integrated utilities, or perhaps competitive services in other instances. This is no small matter, since significant portions of a firm's joint and common costs (typically, administrative and general) are often attributed to the distribution business, even though there is no causal relationship between them. Then there is the designation of a cost as either *customer* or *demand*, which will affect both how costs are divvied up among classes and who within each class will pay them (*i.e.*, both inter- and intra-class allocations). While there is a touch of cynicism in the observation that there is no shortage of academic arguments to justify particular outcomes, it is nevertheless largely true. Always be aware of the revenue effects of a particular rate structure. Who benefits, who loses? Fixed prices, because they recover revenues by customer rather than by usage, invariably shift a larger proportion of the system's costs to the lower-volume consumers (residential and small business). The positions that interested parties take with respect to rate design should, in part, be considered in light of their impacts on class revenue burdens and on the profitability of the utility. Here the admonition to be practical cannot be stressed enough. Seemingly small changes in a rate design can have very significant consequences for different customers.<sup>52</sup>

---

52. Consider the following example (the hypothetical rates cover distribution services only). A residential customer using 500 kWh per month and paying \$0.05 per delivered kWh and a monthly customer charge of \$5.00 sees a monthly bill of \$30. If rates were revised so that residential customers paid a fixed charge of \$20 per month plus \$0.02 cents per kWh, a customer using 500 kWh would receive the same total bill of \$30. For this customer, the rateredesign is revenue neutral. However, for a customer using 300 kWh/month, the monthly bill under the original rate structure is \$20 and, under the new rates, is \$26—a 30% increase, even though there is no change in usage. For a customer using 700 kWh/month, the original bill is \$40 and the revised bill is \$34, a 15% reduction.

Consider a gain the customer using 500 kWh/month. If, under the original rate structure, she reduced her electricity use to 300 kWh per month (whether by load reduction, demand-side management, the installation of a rooftop solar electric system, or some combination of these options), she would reduce her bill by \$10. However, under the revised rate structure, she would only reduce her bill by \$4.

Whether the impacts of a rate design change are immediate and substantial depends, of course, on a variety of factors. The extent to which class cost allocations are altered will determine whether particular customers' total bills (all else being equal) will go up or down. Even those changes that are meant to be class revenue-neutral will affect individual customer bills: as already noted, shifts from usage-based to fixed charges recover disproportionately higher revenues from low-volume users and then, more subtly, there are the effects (both positive and negative) on bills and revenues that flow from demand responses to the changes in rate structure.

## 5. Usage Sensitivity: What's Avoidable?

### a. Peak Demand and Sizing the Wires

Distribution investment is made to serve an expected level of demand over a period of time, often determined by the useful life of the equipment. To the extent that, once a network (or component of it) is built, there is excess capacity in it, the marginal cost of using that excess capacity will be quite low (possibly very close to zero, insofar as there is little in the way of variable cost). It is this phenomenon that the short-run marginal cost of delivering a kilowatt-hour is zero that underlies the argument that there should be no per-kilowatt-hour charge for doing so.

As peak load grows, it will press up against the capacity limits of the system. At the time of constraint, the marginal cost of delivering a kilowatt-hour is, in fact, significantly greater than zero: at a minimum it is the cost of the additional investment needed to carry that marginal kilowatt-hour to end-users.<sup>53</sup> At that point, presumably, the new investment is made, and it is sized to minimize the total costs of delivery over the long term and thus, as before, there is suddenly excess capacity causing once again the marginal cost to fall to almost zero.

This non-linearity of investment with demand is a characteristic of much of the distribution system, the closer one gets to the end-user. To the extent that there are not an infinite number of equipment sizes to enable precise matching of investment and demand, excess capacity is almost necessarily built into the system, from substation facilities to feeders, transformers, customer service drops. But this has less to do with the finitude of equipment options than it does with the least total cost planning objective (optimizing total construction and operations costs over the investment horizon). The analytical key is to view the system over a time period long enough to smooth out the lumpiness of investment in relation to changes in demand.<sup>54</sup>

What emerges from such analysis is the recognition that there are costs associated with load growth, savings generated by reductions in load growth, and savings flowing from reductions in existing load. These values, not necessarily equal to each other, reflect in part the fungibility of significant portions of the system (e.g., substations and feeders). Capacity unused, or freed up, by one customer can be used by others.<sup>55</sup>

Sometimes cited as an interesting and somewhat anomalous characteristic of some distribution investment, specifically that closest to customers (such as the service drop) is its manifestation of positive marginal costs with load growth but seemingly zero marginal (or avoided) costs with load reductions. This is because, so the argument goes, load reduction makes no capacity available for

---

53. And it may indeed be greater, if the value to consumers of that marginal delivery is greater than the cost of the additional investment. See Appendix A.

54. The justification for analyzing costs over the long run, and for setting prices on that basis, is discussed in Appendix A.

55. Chernick, Vol. 5, p. 68.

alternative uses, that did not already exist. This not so, however, because the inability to re-use capacity does not mean that there is no value to not using it. At the very least, future replacement costs can be deferred and the equipment installed on replacement can be down-sized, thereby reducing costs for all users.<sup>56</sup>

The differences in costs and savings associated with load growth, reduced growth rates, and reductions in existing load may leave some room for debate about their implications for rate design; but, given the declining-cost nature of the distribution system, these differences will probably have less of an impact than will the need to recover an embedded revenue requirement. The critical point here is that distribution costs vary primarily with load over the longer term.

#### b. Energy: The Costs of Throughput

As discussed earlier, to the extent that distribution investments are made to offset energy needs, there are necessarily costs associated with avoiding those investments. Losses, heat build-up, frequency of overloads, etc., are aspects of energy use that affect distribution investment and operations; thus there are marginal energy costs in distribution. Whether avoiding those costs make alternatives to distribution cost-effective is an empirical question. But, for purposes of rate design, it is sufficient to say that these marginal costs should be understood and appropriately reflected in rates. They are unquestionably volumetric in nature.

#### B. Conclusion: The Costs of Distribution Services

Cost studies are intended to provide useful information about the causes and magnitudes of costs, to inform a rate design process that is guided by the general principle that those who cause a cost should pay that cost. However, the usual drivers ascribed to distribution costs (both embedded and marginal) describe only part of the story, and the force-fitting of square costs into round drivers can lead to rate designs that will not best promote long-run dynamic efficiency. This is especially true of embedded cost studies, in which a central objective is to assign or allocate costs to particular services or classes of customers, even though many of those costs cannot be assigned unequivocally according to the principle of causation. By their very nature, many utility costs are joint or common to two or more services; consequently there can be no unshakeable assertion that any one service in fact caused a cost and, therefore, that a particular rate element should recover it. And marginal cost studies often suffer from this deficiency as well. This means that regulators should be very careful before relying upon what are essentially (though not necessarily

---

<sup>56</sup> *Id.*, pp. 68-71. Also affected is the magnitude and cost of over-sizing equipment in order to serve forecast demand. See also NERA, pp. 17-18.

unreasonable) arbitrary cost assignments for the purposes of designing rates.<sup>57</sup> Too great a dependence on cost studies is to be captured by their underlying assumptions and methodological flaws. Utilities and commissions should be cautious before adopting a particular method on the basis of what may be a superficial appeal. More important, however, is the concern that a costing method, once adopted, becomes the predominant and unchallenged determinant of rate design.

Marginal cost analysis demonstrates that distribution costs vary with load in the long run. This has important implications for rate design. Embedded cost analysis, though it relies on *a priori* assumptions about causes (and allocations therefore) of historical costs, is useful in rate design at least insofar as it informs the process of reconciling marginal cost-based rates with revenue requirements.<sup>58</sup> We recognize that there are honest disagreements over approaches to both kinds of analysis.<sup>59</sup> But what is important here is for regulators to be aware of the fundamental relationships between costs and demand for electric service, in order to devise rates that best serve the objectives they seek.

---

57. To ensure that [embedded distribution plant] costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. NARUC, p. 89. Interestingly, the manual, in a table on page 34, acknowledges that there is an energy-related component to embedded distribution costs, but is otherwise silent on the question.

58. Bonbright, pp. 366-367. Bonbright expresses some skepticism as to the usefulness of most embedded cost studies for rate design, on the ground that they often ignore the relationship between cost causation and apportionment. One may suspect that the choice of [allocation] formula depends, not on principles of cost imputation but rather on types of apportionment which tend to justify whatever rate structure is advocated for non-cost reasons. *Id.*, p. 368.

59. See, e.g., Chernick, Vol. 5, pp. 58-83, and NARUC, pp. 86-104 and 137-146.