Survey: Electric Cooperative Fixed Cost Recovery

By Power System Engineering, Inc. (PSE)

Costs of providing electric service are increasing and doing so at a faster pace than sales.

Introduction

For many years, electric cooperatives have faced a challenge in aligning rate structures with cost structures. To the extent that there is not alignment, just as in any business, cost recovery, and in particular margins, are put at risk. When both costs and sales are stagnant or at least moving in the same direction, this might be tolerable. However, this is not the case in the electric utility industry. Costs of providing electric service are instead increasing and doing so at a faster pace than sales. Absent rate increases, this environment of rate structure misalignment combined with increasing costs could very well result in reduced annual margins, reduced equity, deferred capital projects, decreased reliability, the inability to maintain capital credit retirements, etc. for many electric cooperatives.

The Nature of Costs

Electric rates for the majority of retail customers in the United States are based on the cost of providing service, which includes: 1) operating expenses and 2) a return or margin.[1] The majority of a distribution cooperative's costs of providing service are fixed; e.g., depreciation, long-term interest, and even distribution operation and maintenance are incurred independent of how much energy is sold. It is also typical for around 50 percent of a G&T cooperative's cost structure to be fixed. In fact, the only variable costs in either a distribution of G&T cooperative's cost structure, at least in the short run, are the wholesale energy costs, which typically represent only one-fourth to one-third of the total cost of service (COS).

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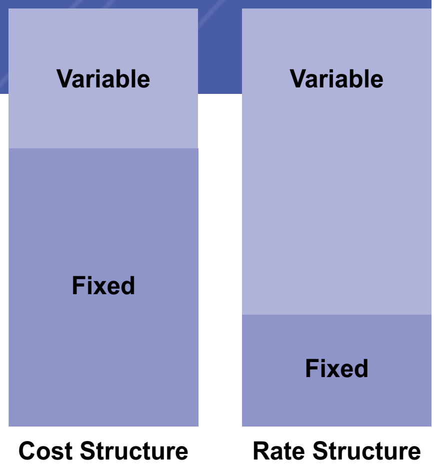
[1] *Even for cooperatives that participate in competitive retail electric markets, customers typically have a choice of cost-based rates. Further, in such competitive electric markets, the local delivery costs remain cost based independent of the power supplier selected.*

The misalignment of cost structures and rates creates risk.



In contrast to its cost structure, the majority of a distribution cooperative's revenue stream comes through variable charges (i.e., energy rates) versus fixed charges (i.e., customer charges). This mismatch between how costs are incurred and recovered creates risk of over or under collection. When energy sales are growing, revenues and margins are typically strong and could even be excessive, producing year-end refunds or deferrals in some cases. This is what some call a "throughput incentive," in that there is an incentive for the utility to increase sales since it will increase profitability. However, when energy sales are flat or even decreasing, margins can shrink quickly and cause the cooperative to take some type of action such as deferring expenditures or increasing rates. In either case, the misalignment of cost structures and rates creates risk.

Residential rates are especially susceptible to this risk. Not only are rates not typically in alignment with costs, but sales to this class of members are also subject to substantial volatility related to weather, economic conditions, conservation, energy efficiency, and to a growing extent, distributed generation. The graph compares a typical cost structure for providing electric service to residential customers versus a typical residential rate structure.

Aligning Rate Structures to Cost Structures

Explaining the above misalignment issues to someone who is not familiar with electric cooperatives or electric rates might solicit a collective yawn. Or, perhaps someone would astutely conclude that we have a pricing problem, and the solution is easy: simply set the rate so that fixed costs are collected in fixed charges and variable costs are collected in variable charges. This is, of course, easier said than done. While many electric cooperatives around the country have redoubled their efforts to deal with this issue, there are difficult legacy issues and, quite frankly, competing rate design objectives that need to be included in the discussion.

Ratemaking has never had a singular goal. Rather, it has long been described as an "art" rather than a "science," an undertaking that often requires a delicate balance between various and often competing objectives of fairness, acceptability, gradualism, price signals, consistency, adequacy, etc., to name just a few.

With that in mind, following is a discussion of the rate structures that electric cooperatives have been implementing or considering to deal with fixed cost recovery risk.

Rate Structures to Consider to Deal with Fixed Cost Recovery Risk:

- **Customer Charge**
- **Straight Fixed-Variable**
- **Demand Charges and Other Options**
- **Grid Charge**

Customer Charge

A step that electric cooperatives have been taking for many years is that of increasing the Customer Charge to recover more fixed costs. In a survey of 35 rate design studies conducted by PSE in the past two years, 34 studies resulted in the Board of Directors approving an increase in the Residential Customer Charge. The average increase was right around $4.00 per month, with the maximum change being an $11.00 per month one-time increase. While a growing number of electric cooperatives have

Increasing the Customer Charge is really a strategic business decision.

increased their Residential Customer Charges to align with their COS study results, the cooperatives in the survey recovered only about 60 percent of the customer cost in the Customer Charge on average. Please reference Appendix A (page 10) for a more detailed summary of the informal survey on customer costs and customer charges, including a reference to the customers per mile of line for each cooperative, which has a significant influence on the results.

A strategy of increasing the Customer Charge is really a strategic business decision. Electric cooperatives around the country may reasonably prioritize certain ratemaking objectives over others based on their specific situations. For example, we often find that this decision looks different for self-regulated cooperatives with a lot of residential and seasonal members, low density, and no municipals in the area than it does for commission-regulated, higher density, suburban cooperatives with a large C&I load base and municipal or IOU competitive pressures. While the former may still find it challenging to increase the Customer Charge, it may be easier for the Board of Directors and member-consumers to appreciate the significant revenue stability and fairness implications. For the latter, the benefits of increasing the Customer Charge are often discounted relative to member relations, economic development, and competitive pressures, although we have recently observed some movement on this front as well.

Increasing the Customer Charge may never be easy, and it may never be the "right time" to make such a change. This is especially true when a substantial gap exists between the current Customer Charge and the appropriate level indicated by the COS study. Unfortunately, some electric cooperatives respond by doing nothing, seeing the challenge as insurmountable. Ideally, the decision of what to do with the Customer Charge can be made on its own merits and then followed with the establishment of an implementation strategy. Two such strategies to be discussed are 1) a planned phase-in and 2) a one-time adjustment.

Gradual or Phased-In Customer Charge Adjustment

When a substantial Customer Charge adjustment is warranted and pursued, the electric cooperative may determine that the magnitude is too substantial to be achieved in a one-time adjustment without causing rate shock and substantial member unrest. A reasonable strategy that a number of electric cooperatives have been pursuing in these cases is to 1) set a goal and 2) plan how to get there. The goal might be to get the Customer Charge all the way up to the COS study result. Or it might be to get it to something less: either a set amount or a percentage of where it "should" ideally be. The plan is then how to get there. Is it a three-year plan, five-year plan, every other year, etc.? Electric cooperatives and their Boards are familiar with setting strategic planning goals, and if increasing the customer charge is an important strategic move, it only makes sense to include a goal with an action plan and prescribed follow-up. Consider the following:

Sioux Valley Energy (SVE) is an electric cooperative serving over 22,000 customers in southeast South Dakota and southwest Minnesota, including areas around Sioux Falls, SD. It averages 3.7 customers per mile of line, with approximately 57 percent of its sales to residential and farm members. Although COS studies had continually demonstrated that SVE's Customer Charge was well below the actual cost, its rate design was historically focused on stability and gradualism. In 2010, a new COS study was completed for a Five-Year Planning Horizon of 2010 to 2014 and was aimed at establishing a Five-Year Strategic Rate Plan to 1) bring individual rate margin levels closer to parity and 2) identify and gradually achieve desired rate structure changes.

Although there were other objectives, a key objective established by the SVE Board of Directors was to achieve a Customer Charge equivalent to 70 percent of its Customer Cost, as determined by the COS study, by the end of the plan. An important side note is that this was coupled with a goal to eliminate the declining block energy charge rate structure over the same time period. Based on a projected COS study for 2014, it was determined that SVE would need to implement a $5.00-per-month increase to the Customer Charge in each of the next five years. This plan was to be updated each year, and the Board would be presented with the new rates to be approved, including the $5.00-per-month increase to the Customer Charge.

Initially, SVE received quite a bit of pushback from the membership. Education on what the charge was for and why the rate structure was being changed helped members understand, if not always fully accept, the change. Debra Biever, SVE's Director of Customer and Employee Relations, cites the importance of not only external education efforts but internal education as well. Together these efforts can help reassure members that the rate restructuring efforts are really aimed at increasing fairness for all members.

Establishing the initial goal at the Board level was critical. As you can imagine, after three years of $5.00 increases to the Customer Charge and with a Customer Charge that was now $35.00 per month,

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There are times when a more direct one-time adjustment may be preferred.

the decision to once again add $5.00 to the charge can get more difficult. If this decision were made in isolation each year, it would be easy to "take a year off." Unfortunately, cost increases do not take a year off; and if this turns into a couple of years, the cooperative has now lost not only momentum but progress. While SVE certainly did reassess its initial goals and plans each year (each year's change was approved annually), it remained committed that the strategy was in the best interest of the cooperative and membership. The result was more progress towards a stable and equitable rate structure than would have likely been achieved if rate changes were relegated to once every three- to five-year decisions.

One-Time Customer Charge Adjustment

Although gradualism takes a prominent place in the context of ratemaking objectives, there are times when a more direct one-time adjustment may be preferred. In this decision, the cooperative needs to weigh the tradeoff of recurring moderate adjustments to a one-time substantial adjustment. Each approach has its pros and cons, and the Boards of electric cooperatives can reasonably differ on their preferences. In either case, but especially with a substantial one-time adjustment, effective communication, engagement, and education are vital. Consider the following success:

Lake Country Power (Lake Country) is a rural electric cooperative serving 43,000 members in parts of eight counties in northeastern Minnesota. Its service territory covers more than 10,000 square miles, and it owns, operates, and maintains more than 8,100 miles of line. Lake Country, similar to other cooperatives in northern Minnesota, Wisconsin, and Michigan, has a substantial portion of seasonal consumers (nearly one-third) including hunting cabins, lake cabins/homes, etc. The level of the Customer Charge is important to Lake Country to ensure not only that the total COS is recovered for the financial integrity of the cooperative but that it is done in a way that is fair and equitable to the part-time and year-round residents in its service territory.

Based on the results of its COS study, Lake Country's Board pursued a rate restructuring strategy. The rate strategy included three options that differed in the "tradeoff" between the Customer Charge and Energy Charge. Option 1 was the most aggressive in that the Customer Charge would be increased to the COS-determined amount of $42.00 per month while the summer and winter Energy Charges would be reduced for all members by more than 20 percent. Option 3 preserved the then current Customer Charge, and Option 2 was essentially a middle ground design with the Customer Charge increase halfway toward the full COS result.

For reasons of financial integrity and fairness, the Board of Directors took a position in support of Option 1. Understanding that this was a big change and an important decision, Lake Country took the options to the streets and ultimately to an advisory vote (i.e., non-binding) of the membership. Over the course of months, Lake Country staff and directors conducted 27 member meetings and 23 media visits (editors, television, and radio interviews) to explain the need for change and to encourage members to vote. Because of the large number of seasonal members from out of the area, it even hosted meetings in the Minneapolis-St. Paul area.

The advisory vote was taken via mailed ballot. Consistent with feedback received during the member meetings, the vote of the membership affirmed the Board's support of Option 1 with the $42.00-per-month Customer Charge and reduced Energy Charges. Over 15 percent of the members voted; and of those, 49 percent voted in favor of Option 1 versus 13 percent for Option 2 and 38 percent for Option 3. With support for its plan, the Board moved to implement a $42.00-per-month Customer Charge in September 2012. According to General Manager, Greg Randa, the change has definitely helped stabilize the cooperative's finances, especially with the volatile weather experienced in the last two years.

What happened next? Well, this is not the whole story, but no major fireworks went off. Sure, there were lots of questions, letters, complaints, and even an opportunity to engage and educate the Minnesota Attorney General's Office. The vast majority of feedback came from members whose primary residence was not in the area. Those members understandably required more attention and explanation since they were not using their home or cabin year-round, and their point of reference was often the IOU or municipal utility serving their home, which typically has a Customer Charge in the $10.00-per-month or less range.

One might wonder about fallout concerning the Board or even impacts on disconnects. While there has been natural turnover on the Board, no seats were lost due to rate restructuring. Disconnects did increase, but not as much as was expected. Lake Country had projected to lose about 5 percent of its seasonal base, but only 3.5 percent was actually lost.

Net Metering Impact on Distribution Revenue Distribution Cooperative Perspective	Gross	Annual 4 kW DG Production	Net Metered
Assumptions			
Annual Energy Consumption (kWh)	12,000	(5,142)	6,858
Annual Energy Purchases (kWh + 5% loss)	12,600	(5,399)	7,201
Annual CP Demand Purchased (kW)	21.3	(8.9)	12.4
Low Customer Charge			
Annual Revenue ($10/mo., $0.11/kWh)	$ 1,440	$ (566)	$ 874
Annual Purchased Power ($15/kW, $0.04/kWh)	$ 823	$ (350)	$ 474
Distribution Revenue	**$ 617**	**$ (216)**	**$ 401**
High Customer Charge			
Annual Revenue ($40/mo., $0.08/kWh)	$ 1,440	$ (411)	$ 1,029
Annual Purchased Power ($15/kW, $0.04/kWh)	$ 823	$ (350)	$ 474
Distribution Revenue	**$ 617**	**$ (62)**	**$ 555**

Distributed Solar PV and Customer Charge Adjustments

The development of distributed generation, particularly distributed solar PV (solar DG), is considered by many to be a movement that will exacerbate fixed-cost recovery challenges. Indeed, if solar industry projections come true, electric cooperatives could be facing a very difficult challenge when it comes to the recovery of fixed costs. For example, under net metering, solar DG owners are able to reduce or eliminate their purchase of energy from the utility through their own generation and in some cases receive compensation for any net excess generation put back onto the utility's electric system (i.e. grid). For a solar DG owner that can completely offset its consumption with generation within a billing period the utility's energy charge can be completely avoided. This is true, even though the customer is relying upon the grid during certain times (i.e. darkness or cloud cover) and requiring the grid to accommodate excess generation that exceeds what they consume onsite during other times. To the extent a solar DG customer is still requiring the utility grid in the same manner but is able to avoid paying for it, costs will be shifted to non-solar DG members. This is generally perceived to be the case; i.e., solar DG members not only rely on the grid for real-time load following but in fact also rely on it for the export of any excess generation. The solar DG member may actually be expanding its use of the grid from a one-way to a two-way street. Absent the installation of capable batteries, it is difficult to see this reality changing or the justification for why a solar DG member should not continue paying for the grid. The key issue then becomes how to ensure that all customers are paying for their use of the grid.

Certainly the previous discussion about customer charges applies to this situation. To the extent that an electric cooperative recovers more of its fixed costs in the Customer Charge, the potential for cost shifting from solar PV can be moderated.

The table illustrates this point by comparing distribution revenue with net metering under two scenarios: 1) a low Customer Charge and high Energy Charge and 2) a high Customer Charge and low Energy Charge. It should be emphasized that the following example only represents the impact on the distribution cooperative, and depending on the G&T wholesale rate structure, there can also be wholesale cost recovery impacts to consider. This type of analysis is also very specific to assumptions made regarding residential load profiles, distributed solar PV sizing and orientation, and especially the G&T's billing peak times.

In the above example, increasing the Customer Charge to recover more fixed costs is a big help toward maintaining recovery of fixed costs. However, it is also notable that even under the High Customer Charge scenario (which is based on a hypothetical COS study), capacity-related fixed costs in energy charges remain that go unrecovered with net metering. Options for recovery of these size-based fixed costs will be discussed in later sections and involve Straight Fixed-Variable (SFV) rate design, Demand Charges, Capacity-Based Customer Charges, and Grid Charges.

Some utilities are using the Customer Charge to address this issue and have implemented a different rate design for solar DG customers. For example, many cooperatives in Ohio have adopted higher customer charges for net metered customers to help recover COS-determined customer-related costs. Electric cooperatives need to be aware of state rules concerning rate design for net metered customers. For example, states like Pennsylvania, Indiana, Missouri, and others have requirements that could preclude charging net metered customers a different rate than non-net metered customers that are otherwise similarly situated.

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If financial stability were the only rate design objective, an SFV rate design would be completely justifiable.

Straight Fixed Variable (SFV) Rate

An SFV rate design recovers all fixed costs in fixed charges and variable costs in variable charges. In this way, the cooperative's margins are decoupled from sales volumes. Under an SFV rate design, decreases in sales would produce a decrease in both costs and revenues on an approximate 1-for-1 relationship, leaving no net impact on margins.

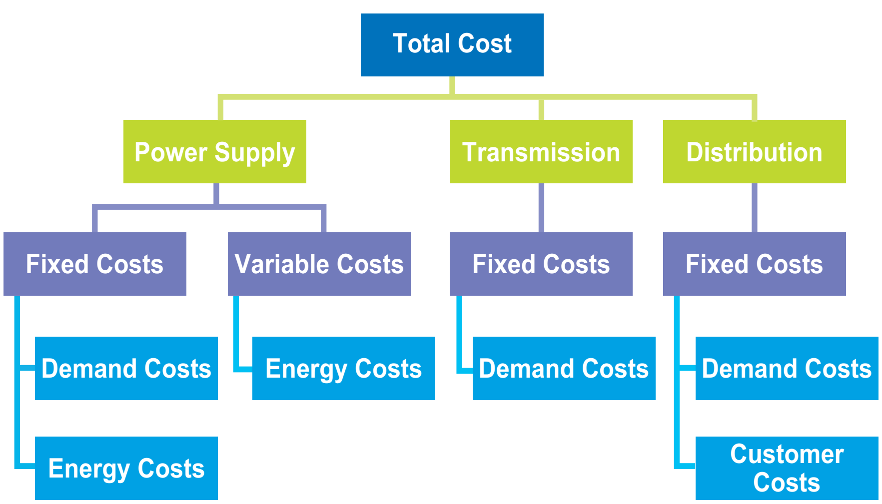
Although this would appear to be a strong benefit of an SFV rate design, in our experience such a rate design is extremely rare for residential electric rates. In Georgia, Missouri, North Dakota, and Oklahoma, SFV rates are used for regulated gas utilities.

As previously discussed, it is not uncommon for electric cooperatives to increase the Customer Charge portion of the residential rate. For an individual customer, the Customer Charge is a fixed charge. However, this is still only a portion of the electric cooperative's fixed costs. Indeed, to recover all of the electric cooperative's fixed costs, including those of the G&T or other all-requirements power supplier, the Customer Charge would need to be something like $85.00+ per month, leaving an Energy Charge in the range of $0.04 per kWh.

It is easy to see why an SFV rate design would be preferred to stabilize margins, especially during times of stagnant or decreasing sales that many cooperatives face today for a myriad of reasons. However, there are several concerns with this type of rate design.

As previously discussed, fixed costs are those costs of providing retail electric service that do not change with the amount of energy consumed. Fixed costs are then billing, metering, labor, depreciation, interest, etc.

It is important at this point to make a distinction between the "behavior" of a cost and the "cause" of a cost. The fact that a cost is fixed only describes how a cost behaves. It says nothing about why the cost exists in the first place; i.e., what caused the cost. If financial stability were the only rate design objective, an SFV rate design would be completely justifiable. However, such a rate design does not adequately consider the principle of causation and thereby fairness.



The cost of owning (i.e., depreciation and interest) line transformers is fixed. However, the cooperative incurs different costs depending on requirements of the customer (i.e., sizing). The same is true of primary line costs. Placing all fixed costs into one fixed charge for a rate class ignores this reality and produces a rate that overcharges member-consumers that require smaller facilities and undercharges member-consumers that require larger facilities. Ironically, this is just the reverse of where most utilities are today. Since for many cooperatives a portion of Customer Costs are being recovered with Energy Charges, high-use member-consumers are overpaying, and low-use member-consumers are underpaying relative to the COS study.

Demand charges can help stabilize margins while being fair to members.

Take an extreme example using the G&T and distribution cooperative relationship. Clearly a substantial portion of a G&T cooperative's cost structure is fixed. Would it be fair for the wholesale rate then to recover these costs on a per-customer basis? Of course, the answer is no. These fixed costs are related to generation plants that were built to provide demand and energy requirements. The fact that they are fixed does not necessarily mean they should be recovered in a Customer Charge.

A COS study is the primary tool used to separate fixed costs between those related to simply providing a path to the member-consumer (consumer-related) versus providing capacity (capacity-related). A proper rate design should consider pricing all consumer-related fixed costs in a Customer Charge and all capacity-related fixed costs in a separate component that accounts for the member-consumer's size requirement.

The question remains then as to how demand-related fixed costs should be recovered if not in the Customer Charge. The answer, as explained next, is that these costs are best recovered in a size-based charge.

Demand Charges and Capacity-Based Customer Charges

An increasing number of utilities, including electric cooperatives, are evaluating or implementing demand charges in residential rate design to recover size-related fixed costs. This is a COS-based rate design that can help stabilize margins while being fair to members. An example of a standard rate design and an alternative demand charge rate design (sometimes called a two-part rate) is illustrated in Chart 1.

The difference in the chart's demand rates is whether the Demand Charge includes only distribution demand costs (Demand Rate 1) or power supply, transmission, and distribution demand-related costs (Demand Rate 2). The Demand Rate 1 design is essentially a way to unbundle the rate for distribution versus power supply and transmission services.

Not many electric cooperatives have implemented a Demand Charge for residential member-consumers. For those that have, it is common for this to be an option rate or to apply for certain-size residential members only. To our knowledge, Black Hills Electric Cooperative in Custer, SD is one of the few that has made this type of rate the default residential/single-phase rate structure. For this cooperative, unless the member does not have metering capability or is participating on the electric heat rate, small single-phase members are charged a general service rate that includes a Demand Charge each month.

There are notable barriers to adopting this form of a residential rate. As indicated in the above example, the cooperative must have billing demand measurements available for each member in the rate class. While this is becoming more common, it is not always the case. In addition, adding a Demand Charge probably means adding another line item/charge to the bill. This is sure to generate some questions from members, especially in situations in which they were not home most of the month but are still billed for essentially the same kW as when they were home. These and other types of questions are relatively common even from commercial members that are typically on demand rates. Both internal and external education and communication again becomes vital. It is not impossible, though, and electric cooperatives would be well served to evaluate the merits and "fit" of this rate design given their situation.

CHART 1

	Standard Rate	Demand Rate 1	Demand Rate 2
Customer Charge	$25.00 per month	$25.00 per month	$25.00 per month
Demand Charge		$ 4.00 per kW	$14.00 per kW
Energy Charge	$ 0.1000 per kWh	$ 0.0730 per kWh	$ 0.0540 per kWh

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A capacity-based Customer Charge has merit as a way to include a size component in the customer charge to collect more fixed costs in an equitable manner.

A rate design that has some similar characteristics as a Demand Charge is a kVA or capacity-based Customer Charge. In our experience, this type of rate design has often been phased out over the past 15 to 20 years, perhaps in favor of simplicity. Yet it has merit as a way to include a size component in the Customer Charge in order to collect more fixed costs in a stable and equitable manner. An example of a capacity-based Customer Charge is illustrated in Chart 2

Capacity Charge 1 represents an effort to simply stratify the existing $21.50 Customer Charge into transformer size categories. The move to place all distribution fixed costs in the Customer Charge by kVA is achieved in the Capacity Charge 2 option. As you can see, based on the size of the transformer, the member will pay for size-related fixed costs of the cooperative. A key challenge of this rate design, as it is with commercial rates that utilize transformer size, is in dealing with excess transformer capacity. For example, if the transformer is 25 kVA, but the customer really only “needs” a 10 kVA transformer, how will the cooperative bill the customer? Further, how will the cooperative handle the customers that share a transformer? These are not fatal flaws, as they can be dealt with in a reasonable manner, but they need to be considered upfront. Perhaps using metered kW (with various “slot sizes”) to scale the Customer Charge rather than transformer capacity resolves this potential issue.

This type of rate can be likened to how many of a cooperative’s members pay for service within other high fixed-costs industries. For example, we generally pay for internet service in a fixed monthly charge. However, that fixed monthly charge changes based on the capacity being requested (i.e., 8 Mbps, 12 Mbps, 50 Mbps, etc.). A customer does not need to know what an Mbps is, but it is widely understood that it has something to do with capacity or speed versus volume. Similarly, cable and satellite television is a fixed charge-based service that depends on the quantity or capacity of channels being subscribed versus how much television someone watches. The parallel should be clear. Electricity’s fixed costs should ideally be recovered through charges that:

1) **Collect a base amount from every customer, and**
2) **Scale up based on size or capacity needs.**

Grid Charges

A Grid Charge, which is similar in purpose and function to a standby charge, can be used to ensure that net-metered member-consumers who continue to use and rely on the grid pay their share of the grid costs and do not unfairly shift these costs to other member-consumers. For example, member-consumers with net metered solar DG still require the grid for times when the sun is not shinning, whether that be at night or during the day when a cloud passes overhead. Clearly, if the member-consumer fully disconnects from the grid, there would be no basis to assess a Grid Charge. This hypothetical disconnection from the electrical grid is similar to developments within the telephone industry over the past decade plus. If a former landline telephone user is not physically connected or using wired telephone service, there is very little basis for requiring them to contribute to the fixed costs of wired telephone service. This is where it is important to make a distinction between the prior example and a distributed solar PV situation. When member-consumers install distributed solar PV, they still rely on the grid to back up or supplement their generation. In fact, some distribution system engineers contend that such a member-consumer requires greater functionality of the grid since they are not only taking delivery of utility electricity over the grid but are using the grid to deliver excess generation produced by their onsite generation, all in real-time.

CHART 2

	Standard Rate	Capacity Charge 1	Capacity Charge 2
Customer Charge	$21.50 per month		
15 kVA		$20.00 per month	$ 66.00 per month
25 kVA		$23.00 per month	$ 90.50 per month
75 kVA and >		$31.50 per month	$168.50 per month
Energy Charge	$ 0.1250 per kWh	$ 0.1250 per kWh	$ 0.0700 per kWh

distribution fixed costs embedded in the Energy Charge and the DG facility produces 500 kWh, then the Grid Charge would recover the $20.00 that would have otherwise been shifted to other member-consumers (500 kWh x $0.04 per kWh fixed costs).[2]

Alternatively, the Grid Charge can be determined based on kW; i.e., typically the kW nameplate rating of the DG facility. In computing this type of Grid Charge, attention must be given to the DG facility's capacity factor, taking into consideration factors that affect energy production such as in solar applications (i.e., losses in power inverters, orientation, etc.). This type of Grid Charge can work well for DG facilities such as solar since the average production is fairly easily predicted to a reasonable degree of accuracy. However, it may require a different charge for different technologies (i.e., wind versus solar). It does have an advantage over a per-kWh Grid Charge in that is it can be applied in any metering setup. With much publicity, the Arizona Corporation Commission (ACC) authorized a $0.60 per kW Grid Charge for net metered customers of Arizona Public Service (APS) in 2013. We are also aware of cooperatives in Colorado, Minnesota, and Wisconsin that have, or are considering implementing, a per-kW Grid Charge for net metered member-consumers.

If member-consumers with DG are able to avoid paying for fixed costs of the grid, then the cost burden (i.e., the fixed costs for which they are not paying) are shifted to other member-consumers. This situation should be avoided to the extent possible. The prior discussion on demand charges and capacity-based Customer Charges is one approach that could be used to ensure all member-consumers pay their fair share of fixed costs. An alternative approach that some utilities, including cooperatives, have implemented and are considering is a Grid Charge.

A Grid Charge, for the purposes of this paper, describes a rate charged specifically to net metering member-consumers to ensure they continue paying their share of the grid fixed costs so that these costs are not unfairly shifted to non-net-metered member-consumers. Conceptually, the charge is set to recoup the fixed costs that would have otherwise been recovered in the cooperative's Energy Charge and which go unrecovered and/or are shifted to others due to net metering.

Grid Charges are typically either expressed on a per kWh or per kW basis. When determined on a per kWh basis, the rate is charged on all metered energy production of the member-consumer's DG facility. This type of Grid Charge application is fairly straightforward, although it does require the metering of production separate from consumption, whereas some cooperatives utilize and in some cases may be required to utilize a single, bi-directional meter that captures only the net energy within the billing period. The key advantage of a per kWh Grid Charge is that there is a direct link between the metered energy production and the costs that would be shifted. For example, if the cooperative has $0.04 per kWh of

Concluding Thoughts

For many, likely most, electric utilities around the country, there is a misalignment of cost and rate structure whereby a significant amount of fixed costs are being recovered over energy sales. This misalignment, while often the result of well-thought-out and balanced ratemaking, puts the margins of electric cooperatives at risk. Especially in light of economic conditions, energy efficiency and conservation initiatives, and increasing amounts of self-supply (i.e., DG), electric cooperatives would be well served to reassess their rate structures. Consideration should be given toward setting retail rates in a manner that stabilizes the collection of fixed costs and does so in a fair and equitable manner. Achieving this will undoubtedly require difficult policy decisions and will require effective communications with the Boards, staff, members, and potential regulators of electric cooperatives. We do not foresee a one-size-fits-all future in this regard; but well-thought-out, planned, and executed strategies will prevail.

Appendix A next page

[2] *In this example, the grid charge is described as recovering only distribution fixed costs that would otherwise be shifted. It should be noted that the cooperative's rate and cost structure will affect the appropriate grid charge for distribution service as would the inclusion of fixed costs related to transmission and/or generation services.*

Survey of Residential Customer Charges and Customer Costs

PSE Residential Customer Charge Survey 2012-2013

Cooperative	Customer Charge Previous	Customer Charge New	Change Dollars	Change Percent	COS Study Reference	Percent of COS Study	Customers Per Mile
Cooperative 1	$ 9.00	$ 10.00	$ 1.00	11%	$ 43.42	23%	5.7
Cooperative 2	$ 10.50	$ 13.50	$ 3.00	29%	$ 33.76	40%	12.3
Cooperative 3	$ 12.00	$ 14.00	$ 2.00	17%	$ 36.78	38%	7.0
Cooperative 4	$ 14.69	$ 16.00	$ 1.31	9%	$ 48.09	33%	6.8
Cooperative 5	$ 17.00	$ 19.00	$ 2.00	12%	$ 30.33	63%	6.3
Cooperative 6	$ 15.00	$ 19.00	$ 4.00	27%	$ 32.77	58%	17.5
Cooperative 7	$ 17.00	$ 19.00	$ 2.00	12%	$ 63.57	30%	2.8
Cooperative 8	$ 11.25	$ 19.50	$ 8.25	73%	$ 30.33	64%	15.9
Cooperative 9	$ 15.00	$ 20.00	$ 5.00	33%	$ 29.85	67%	1.7
Cooperative 10	$ 18.25	$ 20.00	$ 1.75	10%	$ 48.99	41%	1.6
Cooperative 11	$ 18.00	$ 21.00	$ 3.00	17%	$ 37.10	57%	4.7
Cooperative 12	$ 16.00	$ 21.00	$ 5.00	31%	$ 52.62	40%	2.2
Cooperative 13	$ 20.00	$ 24.00	$ 4.00	20%	$ 45.11	53%	4.5
Cooperative 14	$ 16.00	$ 25.00	$ 9.00	56%	$ 29.68	84%	6.2
Cooperative 15	$ 22.00	$ 25.00	$ 3.00	14%	$ 43.27	58%	2.1
Cooperative 16	$ 22.00	$ 25.00	$ 3.00	14%	$ 44.58	56%	2.6
Cooperative 17	$ 15.00	$ 25.00	$ 10.00	67%	$ 57.10	44%	4.9
Cooperative 18	$ 19.50	$ 25.00	$ 5.50	28%	$ 66.55	38%	1.7
Cooperative 19	$ 27.50	$ 27.50	-	0%	$ 44.73	61%	3.5
Cooperative 20	$ 25.25	$ 28.29	$ 3.04	12%	$ 39.64	71%	5.9
Cooperative 21	$ 25.00	$ 29.00	$ 4.00	16%	$ 64.54	45%	1.9
Cooperative 22	$ 28.00	$ 30.00	$ 2.00	7%	$ 36.66	82%	5.2
Cooperative 23	$ 28.00	$ 30.00	$ 2.00	7%	$ 44.11	68%	5.2
Cooperative 24	$ 25.00	$ 30.00	$ 5.00	20%	$ 47.31	63%	11.5
Cooperative 25	$ 28.00	$ 34.00	$ 6.00	21%	$ 46.11	74%	5.4
Cooperative 26	$ 32.00	$ 34.00	$ 2.00	6%	$ 55.84	61%	4.9
Cooperative 27	$ 30.30	$ 35.00	$ 4.70	16%	$ 42.66	82%	7.9
Cooperative 28	$ 32.50	$ 35.00	$ 2.50	8%	$ 44.65	78%	4.7
Cooperative 29	$ 24.00	$ 35.00	$ 11.00	46%	$ 53.08	66%	3.0
Cooperative 30	$ 30.00	$ 35.00	$ 5.00	17%	$ 62.79	56%	3.7
Cooperative 31	$ 34.00	$ 36.00	$ 2.00	6%	$ 56.43	64%	5.6
Cooperative32	$ 32.00	$ 37.00	$ 5.00	16%	$ 54.19	68%	2.2
Cooperative 33	$ 35.00	$ 40.00	$ 5.00	14%	$ 64.41	62%	3.7
Cooperative 34	$ 34.10	$ 43.00	$ 8.90	26%	$ 64.15	67%	0.7
Cooperative 35	$ 43.00	$ 48.00	$ 5.00	12%	$ 72.69	66%	0.7
Average - All	**$ 22.91**	**$ 27.08**	**$ 4.17**	**18%**	**$ 47.65**	**57%**	**5.2**

(The COS Study Reference Column represents only customer-related fixed costs and does not include capacity related fixed-costs related to the G&T and distribution system.)

About the Author

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Mr. Macke has a Masters of Business Administration degree from the University of Minnesota's Carlson School of Management at Minneapolis, MN. He has expertise in numerous areas of electric utility finance, including revenue requirement development, cost of service studies, rate design, dynamic pricing, large load rates and contracts, and financial forecasting and planning. In addition, he has experience in providing litigation support, expert testimony in rate cases, and presenting to utility management, boards, commissions, and industry associations. Mr. Macke is a Vice President at PSE and serves on PSE's Board of Directors and Executive Committee.

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