The Demand for Residential Demand Charges

EPRI Program 182
Understanding Electric Utility Customers
You Ask, We Investigate Webcast Series, 2015, Number 1
Thursday, July 30, 2015
2:00 – 3:30 PM EDT
Agenda

- Origin of demand charges - cost of service rate making
- Residential demand charge rates available today
- Economics of demand charge rates
- Three utility perspectives
  - Salt River Project
  - Commonwealth Edison
  - Pacific Gas and Electric
- Your turn to chime in
Including a demand charge in residential electricity rates has become the subject of considerable, and at times, heated discussion.

The statements above are a sampling of what is being said at conferences, in the popular press, and at hearings to review filings to implement demand charges. Clearly there is a considerable gap between positions.

This presentation will not attempt to resolve those differences, and may add to them. It seeks to contribute to their resolution by motivating stakeholders to approach the issue objectively and completely. It begins with an illustrative exposition of the application of cost-of-service (COS) protocols that are the basis for retail electricity rates in the US. COS assigns costs to classes based in part on some measure of use of system capacity (demand). For a variety of reasons, demand charges have typically not been included in residential tariffs, although including demand charges has been conventional practice with regard to rates for many businesses and most industrial customers. Understanding the implications of levying demand charges to residential customers begins with tracing their origin in cost of service accounting.
Cost-of-service (COS) is a set of accounting rules that are used by utilities to establish retail rates for electricity services. Any service a utility provides is defined by a tariff that stipulates what charges are assessed. The sum of all services provided is set to recover the utility’s revenue requirement, which is a forecast of the cost to serve retail load in the period for which rates are being set. The cornerstone of conventional COS rate-making is the sufficiency requirement; rates are set to recover costs. But, what are those costs and how are they transformed into billable units, for example, $/kw, $/kWh, $/customer/month? How do costs associated with serving demand get assigned to those tariff rates?

The rate-making process involves funneling all cost elements of the revenue requirement through a sequence of assignment processes (functionalization, classification, allocation as shown in the figure) so that all revenue requirement costs end up being recovered through some rate element of class tariff (such as by $/kW/ $/kWh, $/customer month).

For the purposes herein, only three customer classes are considered (residential, commercial, and industrial), and only the three rate elements are included in retail service tariffs that are being developed. In practice, there may be many classes, created by subdividing these three (by
voltage delivery, by presence of a specific end use, for example) and adding services, such as street lighting, backup power for distributed generation resources, wholesale power deliveries (for example to cooperatives embedded in a utility’s geographic market).

We’ll look at a very simple rate structure (customer, demand, energy), which predominates what utilities offer. The observant reader will recognize that virtually any rate structure can be accommodated.
Functionalization - How costs are incurred to conduct the primary physical operations of the electricity system.

Four productive activities are used to account for all the economic actions a utility undertakes to serve retail loads. The elements of the revenue requirement are assigned to these functions. In many cases, the cost is associated with a single functional category. Generation plant assets, O&M, fuel costs, purchase power contribute solely to the production of electricity activity because the output is power that transverses the system providing electricity to end users. Likewise transmission and distribution assets and O&M cost serve those functions uniquely. A meter reader clearly serves distribution needs. Accounting and general cost is a catch-all for cost the utility incurs to manage the system as a whole.

Some costs serve two or more functions, and they must be split among them. Consider linemen and equipment that work on both the transmission and distribution circuits. Does the company’s energy management system only serve the production function, or is the information gathered and processed also used for: transmission operation? Distribution operation? COS protocol contain conventions for making such cross-functional distinctions so that shared costs are
recovered fully, but not duplicatively.

The result of this step is that the utility’s base year revenue requirement is mutually exclusively and exhaustively assigned to the four functions, that now are characterized by millions (or hundreds of millions) of dollars of total functionalized costs, represented by the inset boxes.
Classification associates the functionalized costs with the delivery of measurable services to consumers; a stock (capacity) or flow of power (energy) or connection to the grid that provides access to them (customer). These are measurable attributes of electricity service for which customers can be charged and hence define the tariff rate elements. Classification involves applying COS protocols and formulas that map the functionalized cost to the classifications.
Classification mapping transfers all functional dollars (the rows in the figure), into one of the classification categories (the columns in the figure). The ovals PC, TC, DC, and AGC represent cost allocation rules and protocols from convention as adapted to utility and regulatory circumstances. Some are straightforward, or at least seem to be. Production recovery asset investments are associated with the provision of capacity and hence map to the demand classification, and fuel cost to energy production. The same logical assignment mapping applies to assets and O&M cost for transmission and similarly for distribution. However, there are functional costs that do not serve a single classification, and require sorting, which the cost allocation rules accomplish.

The result is that revenue requirements are now associated with the how electricity service is measured at end-use premises. The next step is to determine which class benefits from the services and by how much.
**Allocation** assigns categorized costs to the rate classes. Allocation is accomplished using established COS protocols and rules. Like all COS protocols, these are conventions that utilities and their regulators have adopted, generally employing methods promulgated by the National Association of Regulatory Utility Commissioners (NARUC) and the Federal Energy Regulatory Commission (FERC), the latter because some jurisdictions provide wholesale services that are FERC-regulated so the utility must harmonize its state and FERC COS rules so all revenues and costs are accounted for and costs are recovered in either retail or wholesale rates.

Direct methods of allocation are used when there is a one-to-one association between a class and the service it is provided. For example, demand costs can be associated with the level of demand, measured in kW, a class requires (its use of system capacity). Likewise energy (kWh) can be mapped directly. Allocating customer costs requires splitting many collective service costs among the classes employing rules that reflect the relative use of system; for example, billing system services costs, utility accounting, and financial and management costs.
Several **direct allocation** are available for each cost classification, apportioning the cost among the classes according to a measure of each's use of system.
The allocation mapping transfers all classified dollars (the rows in the figure), into one of the customer classes (the columns in the figure).

The circles DC, EC, CC and AGC represent allocation rules and protocols from convention as adapted to utility and regulatory circumstances.

The result is that revenue requirements are now characterized in a 4 x 4 matrix; all costs for each classification are mutually exclusively and exhaustively assigned to a class. The next step is determine what class benefits from what services. First, we need to establish use of system to assign costs to each class based on the class responsibility for cost causation.
Class cost responsibility. To convert class-allocated cost to rates, class use of system or billing units must be established for the year.

Sales forecasts determine the maximum demand (System Max kW), the system energy sales (System Annual kWh), and customer numbers for the rate design year. Max kW is assigned to classes according to how much each contributes to the system total. kWh are assigned based on the forecasted kWh use of each class. Load Research (LR) studies establish the relative contribution of each class to the system total, producing for each class a kW, kWh and customer number, indicated in the figure by the boxes, labeled by what they measure kW, kWh, Customer) with a superscript to indicate class (Residential, Commercial, Industrial).

The result is billing units by class aligned with those used in the revenue requirements forecast; what’s needed to calculate class tariff rates, the final step.
Class rates. The allocation step partitioned classified costs by customer class. That result is represented in the figure by the colored boxes on the left of the figure, maintaining the distinction of both classification and allocation. This is necessary to calculate for each class a unique rate for demand, energy, and customer. The class billing units are along the top for class/element, as calculated previously. The task is to calculate the rate ($/unit) for each rate for each class (R, C, I).

The rates are derived by dividing each class/element $ by the corresponding class billing units for that element. To calculate residential demand charges, divide the quantity D/$ in the Demand cost set by Residential Peak kW$.

Moving down to the second row, the residential energy charge is the E/$ from the energy cost set divided by the residential annual kWh.

In the last row, the customer charge is the customer costs for residential customer C/$ divided by the number of residential customers. The A&G $ assignment is left out for simplicity. Generally, A&G costs are lumped into the other categories in the previous step and therefore collected in
the billing elements.

Applying the same sequence of calculations the middle column produces commercial rates and to the last column produces industrial rates.

If residential demand is not metered or demand charges are not levied, then the residential demand costs are lumped with the energy cost and recovered though the $/kWh energy rate.

The result is that all revenue requirement costs have been incorporated into customer class rates elements. These rates produce the revenue requirement if and only if during the rate year, loads by class and rate element are exactly as forecasted. Sales above the load forecast produce revenues that are in excess of costs because they collect a contribution to fixed cost over what is required by the revenue requirement (all other things held constant). Sales below the forecast under-recover fixed costs. This raises issues about how to maintain revenue sufficiency. That's for another day and venue.
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This is a simplification of what is a complex process but it illustrates the fundamentals. Cost-of-service-based rates distinguish and account for demand costs and assign the proper share to the classes based on causation (use of system output). The mechanisms for calculating residential demand costs are already in place if a jurisdiction wants to implement them.

However, the COS-based demand charges may not be acceptable because of other considerations in rate-making, like concerns about the distribution of impacts (demand rates create structural winners and losers relative to an precedent uniform rate) and the rate at which bills change (the increases may be too large to accommodate in one rate change). Can demand charges be assessed to some residences but not others, for example, as a voluntary alternative to an energy-only rate, or solely for customers of specific circumstances, like those that install and operate distributed generation resources (rooftop solar, storage, electric vehicle charging), or resistance space and water heating?

It should be apparent that to make such distinctions fairly and equitably, the entire cost of service study may have to be redone (and maybe even overhauled or completely restructured) to ensure that costs are assigned
by causation. If demand charges are imposed on some customers because their electricity demand is considerably different from that of the body of residential customers, that is tantamount to saying that their cost causation profile is different, because they require new or different levels of system services, or their load shape is different, or both. That defines a new class (or classes) and may require a different way to functionalize costs or assign costs to functions, or allocate them among customer classes.
Residential Demand Charge Rates Band Wagon

- Over 3,000 U.S. utility retail electric service providers
- Serve over 120 million residences
- Over 40 million residential customers are metered with demand charge compatible AMI

- So, how many:
  - Utilities offer residential demand rates? < 1%
  - What % of U.S. residences are served on demand rates < 1%
  - How many are on TOU? > 5%
Note the wide range in nominal levels of the demand charge: from $1.50/kW-month to almost $14/kW-month. Some apply only seasonally (summer) or have different rate for summer and winter. Nonetheless, would we expect that the underlying demand cost for the residential class are that varied among utilities? Much of the difference may be due to rate design decisions including specifying what hours are peak and how many hours a year are peak hours. Other factors and considerations can lead to these differences, for example, the distributional implications (is a hardship imposed on some?), and does setting the demand charge at the COS-specified level result in energy prices that diverge too much from what is considered necessary to reflect marginal cost, avoided cost, other financial or social objectives (promote energy efficiency or use of new efficient uses of electricity)?
Notes From Grabel PowerPoint deck:

**Mid 1970’s**
Residential use of central air conditioning (AC) flourishes in the Phoenix area – begins to drive system peak demand

**Late 1970’s**
APS requests approval of a mandatory residential demand rate for any new home with central air conditioning - charges based on 1) the highest kW demand in a single hour; 2) kWh energy consumed; and 3) a basic service charge Early 1980’s APS implements inclining block and TOU rates and demand rate becomes voluntary

**Early 1990’s**
Almost all TOU Adoption is demand based Early 2000’s TOU Adoption exceeds 40% and demand adoption ebbs to just over 7%

Initially, residential demand rates were marketed with load control technology that would limit peak demand, for example, by limiting an electric clothes dryer or electric water heater from turning on at the
same time as an air conditioning unit

From the presentation (Slide 3) Started in 1981 as a mandatory rate for new homes with central air conditioning
• Today, over 110,000 (11%) customers have voluntarily selected the rate
• APS helps customers select the best rate at time of new service or through website rate comparison tool
• Today's metering technology has enabled this level of sophisticated rate offering
This is a characterization of the split of total utility cost between fixed and variable costs derived from data reported by utilities to Energy information Agency (EIA).
This is a generalization on the split between fixed and variable costs. Because it was derived for aggregated financial data reported by utilities, it does not necessarily comport with how costs are assigned to rates through the cost-of-service and rate design process, and therefore do not necessarily align with determining avoided costs attributable to changes in kW and kWh usage.

Notes on Estimating Fixed and Variable Cost:

- Data are available from a variety of public sources:
  - Detailed financial statements are available for investor-owned utilities from their FERC Form 1 filings.
• Financial statements for most distribution and G&T cooperatives are available from RUS databases.

• Details of sales, revenue, and customer classifications are available in EIA databases.

• Some approximations are required to split total fixed cost from total variable cost.

  • Production O&M is mostly fixed, but the split is not known.

• Further approximations are needed to estimate fixed and variable costs by component in various rate classifications.
The Spain and Italy residential services may look like demand rates, but they differ in that the demand-related charge is not avoidable because it is determined by the characteristics of the premise and the power flow allowed by the metering equipment, not by the use of the system as measured by metered kW.

Demand subscription or priority service combines a reservation charge with a dynamic energy charge. Again, there is no explicit demand charge since the cost of the nominated reservation kW is a fixed/month charge. An exception is if the tariff is symmetric in its application of energy charges: kWh usage over the base pays the posted energy charge and kWh; usage below base results in a bill credit at the posted rate. This is the structure of the two-part RTP rate introduced by Niagara Mohawk over 25 years age and adopted by several others for commercial and industrial customers (most notable Georgia Power). It also bears a close resemblance to telephony residential calling plans - both are from the same rate design principles.
Neither are practical in today’s regulated environment. But they establish the standard by which all other rates should be measured: how much social welfare is forsaken to accommodate other rate design objectives?
Not optimal pricing. Diverting revenue requirements from the efficient energy charge to customer and a demand charge results in welfare losses. Are these worth what is accomplished by doing so?

Not second best pricing. Same as above, second best efficiency is defined by a single energy prices ($/kWh) or prices that reflect time (TOU for example) and spatial (congested load pocket premiums or transmission and distribution cost difference) factors that effect supply.

Two-part pricing. The challenge is to define at what entry fee is an alternative supply sufficiently lower cost that a customer disconnects from the grid? The trick in setting the two-part rate is to identify this threshold and minimize the number of customer outcomes that result in that outcome – by-pass. But, this model is not a framework for charging based on cost distinguished only as being either fixed or variable.
The Voices of Experience

Mark Carroll - Senior Financial Analyst, Salt River Project

Ross Hemphill - Vice President, Regulatory Policy & Strategy, Commonwealth Edison Company

Dan Pease, Manager of Electric Rate Design, Pacific Gas & Electric Company
If this discussion raised more questions than it answered, it was successful. The decision to implement demand charges for residential service, either as the default rate or as an optional service, affects so many factors that no generalization with respect to advice (do it, or don’t do it) is appropriate. Each case requires that stakeholders consider all the salient factors and the implications of tradeoffs among competing objectives. These extend beyond conventional cost of service and rate design issues because residential electricity usage can be influenced in so many ways (price, control technology, distributed generation, community solar, electric vehicle charging).
Questions, comments, feedback?
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Appendix
Useful and Cited References

- Ryan Hledik of Brattle: Presentations on residential demand charges. Recommended pre-reading:
  - His Electricity Journal article (copy also attached):
    - http://www.elsevier.com/about/company-information/policies/sharing#publishedarticle

- Presentations from a recent Harvard Electrify Policy Group (HEPG) session on residential demand charges that reflect different perspectives on demand charges. They are available at HEPG website as cited.

- The Integrated Grid: Capacity and Energy in the Integrated Grid, EPRI 3002006692
Does capacity equate to fixed costs? No.

Does energy equate to variable costs? Producing energy requires fuel and other variable costs, but assets incur variable operating costs based on the rate and level of use.

**Generally**

Fixed and variable costs refers to a high level dichotomization of costs by whether they can be avoided.

Capacity and energy refers to cost categorization of assets and the output of those assets, respectively, constructed from detailed cost data.
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