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RATE DESIGNS FOR CHANGING TIMES

By John Wolfram

The utility landscape is dynamic. Some pundits claim that traditional utility regulation is becoming obsolete. Others are calling for a complete overhaul of utility ratemaking as we know it; distributed energy resources, technology advancements and societal trends are changing the way utilities function. In such turbulent times, how can utilities manage their financials through rate structures? How can utilities bridge the span between the rate and regulatory frameworks of yesterday and tomorrow? One way to do so is to revisit the design of rate offerings available to all utility customers and to residential customers in particular.

Fundamentals

A first step is to remember the broad goals of the utility, which historically have included the following:

- Assure safety, service quality, and customer satisfaction
- Assure the sound financial condition of the utility
- Assure the prudency of utility costs
- Maintain rate stability
- Promote efficient use of energy

While the following goals may not be new, the current climate is driving utilities to renew their emphasis on them:

- Promote renewable resources
- Optimize the use of the grid & customer solutions

Other goals exist but those listed are fairly universal among electric cooperatives, municipal utilities, and investor-owned utilities ("IOUs"). Any emerging rate designs should support these goals.

The Cost of Service Study

Utilities should determine the revenue requirement and perform a cost of service study ("COSS") before initiating any rate design activities. The revenue requirement establishes the annual target for revenues to be produced by rates paid by customers. The COSS assesses how much providing service to each of the utility rate classes contributes to the overall costs of the utility. The COSS identifies the cost to serve each rate class, broken down by function (production and purchased power, transmission, or distribution) and by classification (energy, demand, and customer) in accordance with how the costs vary (by consumption, size, or customer count).

These cost components will serve as the basis for changing the design of rates such that those rates adhere to cost causation principles. The cost components consist of the following for each rate class:

- Production/Purchased Power Energy
- Production/Purchased Power Demand
- Transmission Demand
- Distribution Demand
- Distribution Customer

Rates for each class should appropriately incorporate these components into the charges applied to customer consumption for each billing period.

Challenges with Existing Rates

For many utilities, current residential rates include two components – an energy charge in $/kWh and a fixed monthly service charge (often called a customer charge, facilities charge, or basic service charge) in $/month. This means that the demand, energy and customer cost components listed earlier are "shoe-horned" into the two residential rate components. Often, the demand-related costs and some of the fixed customer costs are built into the energy charge, so that the cost recovery for these fixed costs varies with how much energy the customers actually use. This means that when customers conserve, or when weather is mild, the utility under-recovers its fixed costs. This revenue erosion problem is exacerbated when utilities credit customers with distributed energy resources ("DER") for their self-generation at the full retail rate instead of at avoided costs. This issue – or frankly the *anticipation* of this issue becoming more problematic in the future if the market penetration of DER grows – is driving the focus on emerging rate designs.

Rate Design Options Within the Existing Framework

It is not necessary for utilities to reformulate the entire framework of retail rates in order to address these issues. Options include the following.

1. **<u>Increase the Monthly Fixed Charge</u>**

   Implementing a fixed charge large enough to cover more of the utility's fixed cost can mitigate revenue erosion. The fixed charge should align with the COSS and can include the customer costs and portions of the demand costs. For many utilities, however, the monthly fixed charge is set below cost of service and thus does not cover fixed costs; the customer charge is too low and the energy charge is too high relative to cost-based rates. This is a common problem for utilities, particularly in urban areas where customer density is high. Moving the fixed charge closer to cost of service often results in a reduction to the energy charge. It helps the utility stabilize revenues, reducing exposure to under-recovery (and also over-recovery) of costs during abnormal weather periods.

   A disadvantage is that increasing the monthly fixed charge can increase a low user's bill, supporting the argument that increasing the fixed charge gives a consumer less control over the monthly bill. Critics argue that higher fixed charges harm many customers (especially those with lower incomes who live in smaller homes or apartments, and those with lower electric demands) and are frequently perceived by customers as an effort to punish them for buying less of the utility's product.[1] This can create challenges for utilities to manage with various customer segments, particularly if the existing fixed charge is relatively low.

2. Introduce or Increase the Minimum Bill

Advocates of the minimum bill argue that it ensures that all customers contribute to distribution costs but without encouraging consumption by higher-use customers or raising the bills of lower-income, low-use customers.[2] It also impacts a small number of customers. It can help ensure that DER customers with net consumption of zero and "seasonal" consumers still contribute to the utility's fixed costs. The disadvantage is that many customers do not like the idea of paying a monthly minimum when they don't use much (or any) power, so it can drive down customer satisfaction.

3. Revise Net Metering Policies

Utilities that credit Net Metering customers at the full retail rate are further exposed to revenue erosion. To address this, utilities should credit net metering customers at avoided cost. This assumes a "buy-sell" approach in which the customer purchases all energy consumed on site at the utility's retail rate, and then separately sells all its surplus generation to the utility at avoided cost. Appropriate metering must be in place to allow this revision.

As a policy matter, Net Metering is a contentious topic. Advocates and opponents have diverse views about how the self-supplying customer should be compensated by the utility and about how to determine the value of DER to the grid at large. There is no nationwide consensus on this point right now.

4. Update the Bill Format

As a bridge from a two-part rate to a three-part rate, utilities can revise the format of the customer bill to show the different components that are charged on a per-kilowatt-hour basis. In other words, the utility can separate the existing energy charge into components of purchased power energy, purchased power demand, and distribution demand – all on a per-kWh basis – so that even though the charges are summed at the end into a single energy charge, the customer can see the components, can quantify the impact of each, and can become accustomed to seeing those as separate lines on the bill. This could facilitate the education aspects of a future transition to residential demand rates.

5. Introduce Residential Demand Rates

This includes creating separate charges for customer, energy, and demand for the residential class. Several utilities have offered the residential three-part rate for many years[3] and with the proliferation of Advanced Metering Infrastructure ("AMI") or smart metering, this alternative is becoming more viable than ever before.[4] Utilities have applied three part rates to industrial and large commercial customer classes for decades, so the new aspect of this design is its application to the residential class. Such application requires in-depth research, customer education, and transition planning. Utilities across the country are currently testing this approach with pilot programs, and numerous regulated utilities have proposed such rate designs in proceedings before state regulators. The extent to which utilities (and regulators, City Councils, or Boards of Directors) embrace this option is yet to be seen.

6. **<u>Time of Day ("TOD") or Time of Use ("TOU") Rates</u>**

The cost to produce power varies with the time of day, because as load increases during the day, additional supply resources are dispatched, increasing the marginal production cost. Where possible, a TOD or TOU rate can better match the price signal sent to consumers with the cost of production as it varies during the day. This is consistent with the sale of energy in real-time integrated wholesale markets. Although they can create capacity benefits, TOD or TOU pricing methods largely focus on reducing a utility's energy cost. They can also promote certain technologies, such as distributed energy storage, plug-in electric vehicles, and rooftop solar photovoltaic systems.[5]

For distribution utilities, whether a TOD or TOU rate makes sense depends on whether the wholesale supplier offers a time-varying rate. The structure of the distribution utility energy charge should align with that of the wholesale energy charge – so if the wholesale energy charge is not time-differentiated, the retail supplier offering TOD or TOU rates does so at its own risk.

7. **<u>Three Part Rate with Time of Day Energy Charges</u>**

Another option is the combination of the last two items – a rate with a customer charge, a demand charge, and a time-differentiated energy charge. This alternative provides a more clear price signal to consumers, giving them an incentive to reduce the overall demand (via the demand charge) as well as an incentive to reduce energy consumption during high-cost time periods (via the TOD energy charge). This approach has the combined advantages and disadvantages of the independent elements already described. If smart meter market penetration continues to grow, this type of rate structure is likely to become more prevalent.

Other Rate Design Initiatives

Utilities have other, less traditional alternatives at their disposal to address the changing environment. Some of these are more applicable to IOUs but others can be well-suited for municipal utilities, cooperatives or IOUs.

1. **<u>Formula Rate Plans</u>**

Formula rate plan mechanisms operate using defined formulas to adjust rates automatically and to avoid formal rate proceedings. This approach is commonly used for wholesale transmission or generation ratemaking before the Federal Energy Regulatory

Commission ("FERC"), particularly for annual transmission rate development, but is less commonly applied at the retail level.

With formula rate plans, the formula *is* the rate; the inputs to the rate are specified from auditable financial statements or reports like the FERC Form No. 1, the RUS Form 7 or Form 12, or the EIA Form 411. Other inputs do not change annually but may only change with a formal filing; this usually includes Return on Equity ("ROE"), depreciation expense, Post-Retirement Benefits Other Than Pensions ("PBOP"), or other items. The benefits of the formula rate plan approach include the reduction of both the frequency and cost of rate revision proceedings and the reduction of a utility's financial risk by assuring reasonable margins. The disadvantage is that the formula rate plan can be perceived as putting the utility rates on "auto-pilot" which may result in lower cost containment and less efficient management overall by utility leadership.

2. Future Test Year

Utilities may benefit from changing the "test period" for ratemaking from the historical twelve-month dataset to a projected future twelve-month dataset. Here the data used to set rates comes from the forecast for a time period when new rates would take effect. The principal benefit is that the data will be appropriate for the time period to which it will apply, particularly if the future conditions are expected to differ significantly from the historic conditions.

3. Lost Revenue Adjustment Mechanisms ("LRAMs")

LRAMs adjust utility rates between rate revisions to address the impacts that conservation has on utility sales that were not considered when rates were established. These mechanisms are frequently associated with Demand-Side Management ("DSM") programs, and may be built into a DSM cost recovery mechanism or surcharge.[6] The advantages of LRAMs are that they remove utility disincentives for promoting energy efficiency and reduce the need for more frequent base rate revisions. One disadvantage is that the methods for determining the impacts of conservation may be questionable.

4. Multi-Year Rate Plans

Multi-year rate plans work by holding full rate reviews every three to five years and having automatic rate adjustments in between that focus on external factors. The advantage of multi-year rate plans is that they incentivize utilities to cut costs and improve performance, while also providing more predictable utility revenues and customer rates. Utility customers can potentially benefit from multi-year rate plans in five major ways: (a) lower prices; (b) more moderate price changes over time; (c) utility supply of more services; (d) higher reliability and improved customer service; and, (e) more immediate price benefits from improved utility performance.[7] The disadvantage is that potential volatility and/or changing circumstances may not be accounted for in the process. The benefits to utility customers come down to how the plans are structured and executed. Certain features should be in place, for example to protect customers from excessive rates, to give utilities incentives for cost-efficiency, and to ensure customers that utilities are performing satisfactorily in vital areas such as service quality.[8]

5. **<u>Straight Fixed Variable ("SFV") Rates</u>**

SFV Rates allow the utility to recoup nearly all fixed costs through fixed monthly charges (per customer-month) or peak demand charges (per peak kW) that are independent of the volume of electricity consumed (in kWh). The benefits of SFV Rates include improving utility recovery of fixed costs, mitigating the need to adjust rates in response to load changes, and removing disincentives for utility promotion of energy efficiency. SFV rates are a strong tool for revenue decoupling, but can be challenging due to the impacts on low-use or low-bill customers. They may also fail to recognize the cost differences between small and large customers (which can create challenges for utilities with diverse rate classes) and promote consumption relative to using volumetric pricing.[9]

6. **<u>Earnings Sharing Mechanism ("ESM")</u>**

The ESM allows for rate adjustments when actual earnings fall outside of a pre-determined band. This is most often applicable to IOUs. Usually the allowed band is comprised of a minimum and maximum ROE. When the actual ROE falls within the allowed bandwidth, no rate change occurs; when the ROE falls above the bandwidth, customers receive refunds, and when the ROE falls below the bandwidth, customers pay a surcharge. The amounts outside the bandwidth are split between ratepayers and shareholders (hence the "sharing"). The ESM can provide lower procedural costs and reduce risk. However, compared to traditional ratemaking, where rates remain fixed between rate cases, an ESM would diminish regulatory lag, which could reduce the incentive of a utility to control its costs between rate cases. The ESM could also shift a larger share of risk from shareholders to ratepayers.[10]

7. **<u>Performance Based Regulation ("PBR")</u>**

For some regulated utilities, legislators or regulators have adopted PBR in order to offer financial incentives to utilities to improve service quality and performance. Sometimes this approach is adopted in response to some type of service decline or performance deficiency on the part of a utility. Some experts assert that PBR promotes a shift from cost of service to value of service and provides a way for utilities, customers, and broader society to meet their respective goals; setting performance metrics beyond investment in assets connects shareholder value to the customer and rewards utilities for reaching agreed-upon policy goals.[11] For this reason, the proper establishment of performance metrics is essential to the success of this approach.

The Role of Smart Metering

The use of smart metering or AMI allows the utility to measure, use and analyze residential customer consumption data in ways rarely possible before. AMI is a necessary first step in the broad implementation of time varying rates, demand response programs, and related customer offerings. As costs decline and technology improves, residential smart meters are likely to become more commonplace. As this happens, more utilities will be positioned to adjust their rate offerings accordingly.

Conclusion

Utility regulation continues to evolve. Changes to the ratemaking framework will be driven by shifting customer interests, the market penetration of DER, the extent to which utilities adopt AMI and smart grid technologies, revisions to wholesale markets and pricing, developments in end-user technology, and other drivers. Utilities can respond to these changes by revisiting the structure of their rate offerings, by remaining committed to their long-standing and emerging goals, and by remaining alert and flexible. In this way utilities can be best positioned to bridge the span between the rate and regulatory frameworks of yesterday and tomorrow.

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Endnotes:

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