RATEMAKING AND RATE STRUCTURE: NEW PARADIGMS PART THREE - NEW RATEMAKING MODELS

In Part One, we looked at the challenges that utilities face related to the increased expenses that are required to introduce “grid modernization,” which is more and more being expected by policymakers - legislatures and regulatory bodies. In Part Two, we looked at the second challenge - how utilities are expected to come up with this extra money while often facing declining revenue as a result of reduced utility-generated power demand from customers.

Here, we look at new trends in ratemaking - and how some of these forward-looking models might actually allow utilities to receive the rates they need in order to address both challenges.

Models of Ratemaking

Ratemaking has an economic dimension, in that it attempts to set prices at competitive and efficient levels. However, it also has a political dimension, in that the service is considered an economic necessity, and rates must be fair across different classes of consumers.

Traditional: The traditional ratemaking model involves two separate processes that are used in order to determine what is considered an acceptable rate.

The first is long-term Integrated Resource Planning (IRP). IRP uses projections of costs and benefits to determine whether a utility should procure a specific resource. IRP models a wide range of costs and benefits from possible expenses, usually over a period of 20 years or so, and then determines the “least cost, best fit” portfolio of resources and infrastructure.

The second is short-term revenue requirements based on cost-of-service ratemaking (COSR). COSR, unlike IRP, uses actual and measurable data to answer the question of how much customers should pay for a resource once it is procured. COSR, which is based on historical usage and cost data, identifies a utility’s revenue requirements for its next rate period, which tends to be one to three years.

While IRP and COSR tended to work well in the past, there are those today who claim that they are unable to take into account the introduction of the new technologies that are necessary for “grid modernization.” That is, the traditional ratemaking is unable to attribute the long-term value of the new technologies being introduced. The traditional model leads to a further disadvantage to the utility if customers are the ones who own the technologies, since there are no ROI opportunities for the utilities.

Test Year Determination: Also important in the mix is how a “test year” is determined. Data from the “test year,” which allows the comparison of a defined period’s total rate base costs, including operating expenses with its total revenues from electricity sales, is used to estimate future rates.

Currently, the majority of U.S. utilities determine expenses and sales using a “historic test year” (HTY) approach, which begins with actual revenues and sales of a recent year and sets rates based on adjustments for known and measurable changes.

However, more and more utilities are beginning to use a “future test year” (FTY) approach, with which new rates are set based on detailed forecasts of expenses and sales. One reason for the growing interest in FTY is that, with utilities facing flat or declining revenues, the HTY model will end up providing an inaccurate view

of what will likely happen in the next year. HTY tended to work well years ago when utilities' revenues were growing faster than their expenses.

While utilities find the FTY concept appealing, a number of consumer advocates tend to be less excited, claiming that the model provides utilities with incentives to overstate estimated expenses and understate estimates sales.

Multi-Year Rate Plans: Utilities are also gravitating more toward seeking multi-year rate plans (MYPs), which are often set for three to five years and include mechanisms that allow rates to escalate according to a predetermined schedule set during the ratemaking case. MYPs tend to be appealing to utilities, because they are able to provide more predictability.

Performance-Based Ratemaking: With utilities now facing new technology requirements and declining demand, even FTY combined with MYP may not be an appropriate and fair model. Faced with the realities of demand for new technologies as well as reduced load demand, more and more utilities are pushing for the adoption of performance-based ratemaking (PBR).

PBR starts by identifying the things that utility customers want, and then using a stakeholder-based regulatory forum to create opportunities for the utilities to earn money by meeting customer needs and wants.

While the traditional utility infrastructure was one-directional and linear, PBR takes into account the new bi-directional flows that are occurring with grid modernization, as well as the bi-directional value transactions that are necessary to properly determine values.

In sum, the utility of the future will no longer be today's utility. Rather than a basic provider of energy to customers, utilities are in the process of revising what their core business should be, and how revenues can come from this new business model. PBR can take this into account.

In specific, PBR is able to take the value of DERs into account, because it compensates utilities for delivering what their customers want. That is, when utilities are rewarded with incentives for providing what customers want, they will identify and offer the low-cost opportunities related to DER technologies. In sum, while profits using a COSR model depended on returns on capital investment, profits using PBR will be determined by meeting policymaker-set goals based on customer demand.

Currently, over a dozen states are working on introducing the PBR model.

An ideal scenario seems to be PBR combined with MYP, which allows utilities to shift their focus from capital expenditures to performance incentives, without having to spend as much time dealing with short-term rate cases.

New Ratemaking in Action

In June 2018, the governor of Pennsylvania signed legislation authorizing the state's PUC to allow for a new range of options in crafting future rate designs. Pennsylvania is one of a growing number of states moving in this direction. "I support this legislation, because I believe it offers the Commission new tools to encourage innovation, ensure grid reliability, and promote energy efficiency and renewable energy," said the governor.

The new law provides a range of options for utilities to offer to regulators for ratemaking, including: decoupling mechanisms, which break the linking between the amount of energy a utility sells and the revenue it collects to recover the fixed costs of serving customers; PBR; formula-based rates; multi-year rate plans; or some combination of all four.

And utilities are seeking and gaining approval for even more. As has been the case with a growing number of utilities in recent years, Eversource Energy, a New England-based utility, has been noting that, without new revenues to replace displaced distribution revenues, distribution system infrastructure and maintenance costs must be shifted to non-DER-owning customers. In 2017, Eversource asked the Department of Public Utilities (DPU) in Massachusetts for a new rate designed to recover growing displaced distribution revenues. In November 2017, the DPU addressed part of Eversource's request by approving a $36.4 million revenue increase, a PBR mechanism, and funding for electrical vehicle infrastructure and energy storage programs.

In January, the DPU completed the process by addressing rate design, approving Eversource's request to adopt a monthly minimum reliability contribution (MMRC), which will be used as a mandatory demand charge for residential customers who own DER and who earn remuneration via net energy metering credits for the electricity that their DER systems export back to Eversource. This DPU decision makes Eversource the first regulated electric utility in the nation to win approval for such a charge from state regulators. The demand charge, which has been common for industrial and large commercial customers, will impose a higher per-kWh charge for the kWh used during a DER-owning residential customer's highest 15 minutes of electricity consumption each month.

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