SPEER

The South-central Partnership for Energy Efficiency as a Resource

Win-Win Utility Regulation in an Era of Energy Innovation

Whitepaper prepared for The SPEER Commission

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About the South-central Partnership for Energy Efficiency as a Resource (SPEER)

SPEER is an Austin, Texas based non-profit organization dedicated to increasing and accelerating the adoption of energy efficient products, technologies, and services. Much of SPEER's work focuses on finding the best market-based approaches to increase energy efficiency and overcoming persistent market barriers. The views expressed in this paper do not necessarily reflect the views of all of SPEER's members, funders, or supporters. For more information about SPEER, please visit: www.eepartnership.org

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I. SUMMARY

The changing role of utilities and the electric grid has received much attention in recent years across the United States. This paper focuses on the relatively unique model of the restructured transmission and distribution utilities (TDUs) in the areas of Texas open to retail competition within the Electric Reliability Council of Texas (ERCOT). These utilities provide delivery services to the majority of the electricity load in the state of Texas. Although Texas has continued to grow, both the rate of economic growth, and particularly the rate of growth in demand for electric power, has slowed from its historic pace. At the same time, due at least in part to the rollout of advanced metering infrastructure and extensive transmission upgrades to integrate significant renewable energy generation, transmission and distribution costs have risen significantly. In the past decade, TDU charges to residential customers, for example, have increased by an average of over 35% (to about $45 per month),

We find that the current revenue recovery regime is an artifact of the vertically integrated utility of the past, and has grown out of alignment with the current and projected role of the TDUs, particularly in this market. We provide context by discussing some of the most significant trends with implications for the utilities going forward, including the proliferation of distributed energy resources (DERs) and consumer centric energy management tools. And we discuss the growing pressure to consider non-wires alternatives--the potential to cost effectively substitute traditional infrastructure investment with targeted DERs. And lastly, we suggest an alternative paradigm for TDU revenue recovery that includes updated policy goals, system cost-based price signals to consumers, and utility performance incentives. We seek to provide sustainable funding for utilities and their shareholders, but in a manner that fosters technological and commercial innovations that result in increasingly more affordable, more efficient, and more reliable utility services.

Private and public companies providing certain “utility” services have been granted monopolies over certain geographic areas, out of recognition that such services are critical, and more efficiently delivered by single consolidated providers. That is, allowing these utilities, including electric power, gas, and water utilities, for example, the exclusive right to build a region’s critical infrastructure is more efficient for society than building competing infrastructures. As part of this utility compact, however, utilities agree to submit to regulation of their services and charges by the state.

In the areas of Texas in which retail competition is permitted, the role of investor-owned utilities (IOUs) have been stripped down more completely than in any other markets. They essentially provide only the poles, wires, transformation and related infrastructure for the reliable transmission and distribution of electricity, and the metering infrastructure to measure the delivery of power and energy to end users. Power generation and retail services have been “unbundled” and are now competitive endeavors, although some of these elements take place through a structured wholesale energy market.

This whitepaper addresses rate regulation by the State of Texas of investor owned utilities in the ERCOT market, which serve about 60 percent of the load within the ERCOT footprint. While all electric utilities share some of the same challenges as technologies, policy priorities, and customer expectations change over time, the unbundled transmission and distribution utilities (TDUs) within the competitive market are unique, in part because they have less control over what takes place within the competitive markets they serve. Competitors, whether retail electric providers or other third-party energy services companies emerging in these markets, look to the utility to facilitate market innovation, but the regulated revenue recovery process for utilities may provide mixed incentives to utility executives. We explore here how that process may need to evolve to sustain these important players in our economy, and align their interests with their customers.

Traditional revenue recovery for transmission and distribution utilities (TDUs) that have a service monopoly in a given territory is generally based on the inputs required to deliver an acceptable level of service. The Public Utilities Commission of Texas, for example, begins a general rate case by determining the utility's costs, including the cost of capital, and amount of invested capital in a contemporaneous test period, adjusting those costs, if necessary, to reflect the expected conditions in the period that the rates will be in effect. The commission then determines a reasonable rate of return to allow the TDU on invested capital required to attract investment capital, considering the relative level of risk. This traditional "cost of service" revenue recovery approach has worked well for many years to support and encourage the investment of capital in infrastructure needed to reliably support the growth in demand, and the growth of the economy generally.

The Commission then sets rates the TDU can charge its customers, in order to allow it the opportunity to recover the level of revenue authorized to cover those costs and earn a positive rate of return on its invested capital above the cost of capital. Rate design for TDUs in the ERCOT foot print is somewhat simplified because retail and generation functions are no longer a function of the utility. TDU rates are charged directly to competitive retail companies for inclusion in retail bills to their customers. Today TDU charges for larger commercial and industrial customers (>10 kW) are based on the level of demand, but mass market customer rates are set by dividing the cost to serve that class by the expected volume of retail energy sales. The objectives of ratemaking include setting rates that are just and reasonable, and that are non-preferential or non-discriminatory.

The overall purpose of utility regulation, however, is to emulate the conditions that would exist if there were a competitive market for the service the utility provides, or elicit the kind of behavior one might expect of a competitive firm. And, regulatory commissions must also be responsive to policy direction, and have the ability to alter either the authorized total revenues, or the design of rates through which those revenues are collected from customers, in response to policy priorities. For example, a utility may be allowed a slightly higher rate of return on its investment if it achieves lower levels of local system outages. Rate design is generally based fundamentally on cost causation for various rate classes (e.g., residential, commercial, industrial), but may also be designed to pass on certain price signals and encourage particular behavior. For example, fixed charges for all of a utility's fixed costs have generally not been adopted, because they are thought to discourage energy efficiency investments by customers and may have disproportionate impacts on low-usage customers.

II. CONTEXT FOR CONSIDERATION OF ALTERNATIVE RATEMAKING MECHANISMS

The environment in which electric utilities operate is becoming more complex, and less predictable, as a result of the proliferation of increasingly affordable distributed generation (DG) technologies, the market penetration of energy efficiency and other consumer demand-management technologies, electric vehicles and emerging electric storage technologies, all of which are today generically referred to as distributed energy resources (DERs). The adoption of these technologies tends to reduce consumption levels for customers, and require utilities to acquire new technologies or information systems capacity to manage their distribution systems. The accelerating proliferation of DERs, then, simultaneously increases costs and reduces customer consumption.

One implication of these developments for utilities is that the current utility rate design paradigm in Texas, which has worked well in the past, may be poorly positioned for a future in which many customers have cost-effective options to improve the energy efficiency of their homes and businesses or generate electricity onsite. If distribution costs and rates increase, more customers are likely to seek ways to reduce their consumption or generate electricity at their homes and businesses, further exacerbating the utilities' predicament. TDU rates for residential and small commercial customers are structured in a way that is suitable for commodity sales, with around 90% of revenue coming from volumetric (kilowatt-hour) energy charges. Thus, while state policy now mandates that ERCOT TDUs not be in the business of producing or selling the commodity, they recover a significant amount of revenue through volumetric pricing. As more customers reduce their total energy use, utilities must be able to raise rates to recover the same level of revenues to cover their costs. This is the legacy of a previous era, when vertically integrated utilities included generation and retail services in their rates, and when advanced meter infrastructure limited the information available upon which customers might be billed. This mismatch between the ways costs are incurred (a high percentage of fixed costs for delivery capacity) and recovered (largely through volumetric charges) will be an increasingly significant challenge for TDUs in the changing environment in which they find themselves.

III. DERS: AN OPPORTUNITY AND A CHALLENGE

The proliferation of DERs, including DG, energy efficient and intelligent appliances and building systems, demand response, and electric storage, is both an opportunity and a challenge. Widespread customer adoption of DERs can reduce a TDU's revenue and require it to invest in additional control equipment, for example, but, depending on their nature and deployment, DERs may also reduce utility costs. For example, in an area where load growth on a utility's distribution network promises to exceed local capacity, a utility might avoid expensive upgrades to distribution facilities, if customer efficiency or distributed generation reduced peak demand on that part of the distribution system. Thus, utilities could use DERs to avoid or delay the distribution upgrades in several ways:

- Energy efficiency programs could be targeted to reduce the need for new distribution facilities in areas experiencing growth in demand.

- TDUs could collaborate with DG providers and customers to encourage non-wires alternatives to transmission and distribution system needs.
- TDUs could facilitate the deployment and intelligent use of advanced energy storage or management and control systems to help increase the utilization of the transmission and distribution assets.

These are all examples of things a utility would not be incented to do today, however, under the traditional revenue recovery framework we have called the "cost of service" model. By expanding its investment in capital infrastructure, the utility expands the base upon which regulation allows it to earn a return. A utility is still incented to increase its operational efficiency to hold down its costs once a rate is established, but not generally to help customers reduce their demand or consumption as well. Many states are now considering how utilities might be incented through regulation to adopt "non-wires alternatives" particularly where such alternatives provide a higher-quality or lower-cost outcome. Even where commissions consider allowing a utility to earn a return on the cost to avoid larger investment requirements, they must consider opportunity costs.

A new regulatory paradigm, including both defining the revenue requirement and designing the rate structure, may be needed to provide the proper incentives to utilities to take advantage of the opportunities inherent in the proliferation of these technologies, and to send appropriate, complementary price signals to consumers.

IV. A NEW PARADIGM FOR TEXAS UTILITY RATES

SPEER previously investigated this challenge with respect to how it impacts a utility's willingness to administer energy efficiency incentive programs.[1] As a result of that more narrowly focused research, SPEER concluded that a comprehensive approach to utility administration of energy efficiency programs should include:

- A clear goal for energy efficiency results;
- Mechanism(s) for the timely recovery of program costs;
- A means for the timely recovery of lost revenues from reduced energy delivery volumes or "throughput;" and
- Performance rewards for the utility for cost effectively exceeding energy efficiency goals in proportion to the savings created.

This comprehensive approach gives the company its mission, makes it neutral with respect to the impact on its bottom line or ability to create value, and provides positive incentives for meeting or exceeding

[1] *Efficiency and Ratemaking: Aligning the Interest of Utilities and their Customers*, SPEER, March 2016, available at EEPartnership.org.

goals. We noted that Texas currently provides each of these elements for utilities with respect to their administration of efficiency programs, except the recovery of lost revenues. This is why Texas IOUs are reluctant to attempt more than the modest efficiency goals adopted today, which places the state below the average per capita investment in efficiency of all the states.

Now, in considering how to create a regulatory environment to address the broader operations of utilities in the changing market, we realized that a similar comprehensive approach may be feasible and appropriate. That is, to address the challenges Texas TDUs face in connection with the proliferation of DERs, and changing expectations of market participants including consumers, regulations should:

- Set clear performance goals to encourage customer empowerment, operational reliability and efficiency, environmental sustainability, and market innovation;
- Allow cost recovery for a utility's costs to achieve these goals;
- Replace the TDU's lost revenue resulting from lost sales and/or lost investment opportunities; and
- Create positive or symmetric performance incentives.

V. Utility Goals in a High DER Environment

Regulatory goals and incentive payments for utilities that meet these goals have been used for a number of years in a number of states. Goals that have been used in utility regulation include key values such as reliability, safety, and customer satisfaction. Potential goals for a high DER environment might include the following:

- <u>Customer Empowerment</u>—This goal includes facilitating access to AMI data for customers and their third-party retail electric or energy services providers of choice. This access to data facilitates appropriate customer decisions with respect to investments in distributed energy resources that also contribute to the efficient operation of the grid, and that help avoid or reduce the need for additional capital investments by the TDU. It includes facilitating participation of loads in the wholesale or emerging markets for energy, capacity, reliability, or ancillary services, through appropriate price signals or other market information, market-neutral performance incentives, or financing.
- <u>Operational Reliability and Efficiency</u>—This goal includes improving the safety, security, resilience and rapid recovery capacity of the grid, and associated information and communication systems. This should particularly include increasing the overall utilization of the TDU's existing assets. This can be achieved through investment in asset monitoring and controls technologies that allow more accurate understanding of actual system capacity. It also includes leveraging internal capacities to optimize the contribution of third parties,

including competitive retailers and their end use customers, such as targeting energy efficiency incentive funds, or stimulating investments in DERs to avoid or defer capital upgrades, or improve system performance.

- Environmental Sustainability—This goal should involve facilitating the de-carbonization of various industries through electrification, and facilitating the integration of clean energy resources.
- Animation of Market Innovation—This goal is the flip side of customer empowerments, and also requires the TDUs to facilitate simple, convenient access to system information and AMI data for customers' chosen competitive services provider. It includes a transparent and streamlined interconnection process. And, it includes providing information and technology-neutral incentives that encourage the emergence of information-driven energy management services, and appropriate deployments of efficiency and other distributed energy resources.

VI. Cost Recovery

Although Texas continues to rely upon a traditional cost of service approach to ratemaking generally, it has taken a number of steps to help assure utilities a stable revenue environment through the adoption of a number of "rate trackers," or automatic adjustment factors. These include Transmission Cost Recovery Factors, a Distribution Cost Recovery Factor, an Advanced Meter Cost Rider, and an Energy Efficiency Cost Recovery Factor. There are also adjustment factors applied to specific utilities, for example, such as a storm recovery adjustment factor for CenterPoint Energy. These mechanisms can help allow a utility to go for several years without a general rate case, and have contributed to a relatively positive and stable environment for investment in TDU infrastructure.

Adoption of the Distribution Cost Recovery Factor was allowed by the legislature temporarily and is set to expire in 2019. Distribution costs are very important to the TDUs as they make up 60% of a TDU's costs, although only CenterPoint and AEP currently have an approved DCRF. Nevertheless, extension of the authority to apply the Distribution Cost Recovery Factor may be appropriate, especially if it is adopted as part of a more comprehensive system of regulation as described here.

Addressing cost recovery of the utility's costs for managing and even enabling the targeted development of DERs on the grid can also be relatively straight-forward. Other than allowing the costs in a TDU's general rate case, the Distribution Cost Recovery Factor, or a rate tracker established for the DER specifically could be used to recognize the heightened level of activity being required of the utility.

VII. Lost Revenues

Targeted adjustment factors largely address additional or new costs that the utility encounters, not anticipated in the last general rate case, however, and do not adjust the rate recovery of the utility to account for other factors affecting its general level of revenue collection. For example none of the cost trackers or adjustment factors would make the utility whole if it successfully enabled increasing rates of DER adoption reducing throughput significantly. So, they do not fundamentally address revenue loss as a disincentive to enable or encourage distributed resource development.

Beginning in the 1980s states experimented with an approach called 'decoupling,' to address this concern. This was when efficiency incentive or assistance programs were first being developed in the states, and it was intended to make the utilities neutral toward lost revenues associated with their administration of efficiency programs. Decoupling is basically a mechanism to adjust rates periodically to ensure the amount a utility booked as revenue was no more and no less than the amount of revenue authorized by the regulators. It changes the driver of revenue from energy use to a basis approved by the regulator in the decoupling mechanism design, which makes it a somewhat abstract and inexact practice.

Decoupling can become a relatively involved and expensive regulatory process in which regulators periodically (monthly, annually) determine how much the utility can adjust its rates to account for various factors which may be beyond its control. At the same time, history has shown that decoupling mechanisms in the states have not actually been used to adjust the rates very dramatically. And, while decoupling alone does appear to help remove the disincentive of lost revenues it doesn't address the regulatory goal of replacing the competitive pressures of the market to spur innovation and continuous improvement.

A decoupling mechanism separates a utility's revenues from its sales volume without affecting its rate structure. For that reason, at this point in history, decoupling has also drawn concern that rate adjustments associated with accelerating adoption of efficiency and other DERs is unfairly shifting the cost of utility infrastructure off to other consumers. This is becoming most dramatically apparent in states like California and Hawaii, where market penetration of DERs is already very significant.

Interestingly, some people also use the term 'decoupling' to refer to certain rate structures, such as straight-fixed-variable rates, that tend to have a similar effect. That is, if a utility charges customers a fixed fee to cover fixed costs and a variable charge in proportion to usage, accelerated adoption of distributed resources like efficiency or on-site generation have less effect on utility revenues. We tend to lean toward adoption of a version of this approach, as both more concrete and predictable, and more market-based than decoupling. This approach to stabilizing utility revenues in a period of rapid DER adoption is discussed further in the section further on in this paper on rate design.

VIII. Opportunity Cost

A more complex challenge of lost revenue adjustment for utilities in the current age is how to address lost opportunity costs. While we have outlined a number of goals for utility performance from the perspective of ratepayers, one goal of an IOU's management team is also to create value for its shareholders. The current regulatory paradigm in Texas still rewards a utility for capital investment in its own plant, because it receives a return on capital investment but not on expenses, even expenses associated with efficiently avoiding capital improvements. This leads it to prefer traditional infrastructure expansions to non-wires alternatives, even if they are more efficient, or deliver superior results. For this reason, utility management could be expected to prefer internal capital investments over collaborative solutions with third parties, certainly their shareholders would. Full cost recovery and decoupling together would not address this issue.

To overcome this disincentive to actively seek innovative and collaborative synergies with third parties, including retailers and their end-use customers, determination of the appropriate revenue recovery must take into account the utility's cost of giving up more lucrative investments. Doing so does not remove the potential for win-win solutions, where consumers and utilities are better off.

As a simple example, suppose a utility experiences load growth in an area that it projects will require $1 million in capital investment in distribution facilities. If the TDU could modify the load growth or control demand by paying incentives of $50,000 to third parties for appropriate operation of DERs (efficiency, demand response, storage), all customers would benefit from the overall reduction in costs to be incorporated into rates, as well as perhaps from the stimulation of the economy, technological innovation, or greater resiliency.

If the utility's allowed rate of return is 10% and the depreciation rate of the avoided distribution facilities would be 5%, the utility would avoid revenue requirements of about $150,000 a year for the life of the facilities.[2] Thus, the impact on the revenue that the utility would need to recover from its customers would be $50,000, instead of $150,000.

A regulatory construct consistent with the goals outlined in this whitepaper would encourage a utility to make the more efficient investment. Therefore cost recovery rules should first of all clearly allow the utility to be granted a return on this kind of expenditure that is comparable to the return it would expect to receive on a capital improvement to its own system. Similarly a utility that chose to invest in cloud computing might achieve greater cyber security at lower cost than by building its own infrastructure, but receive less reward from the regulatory system as it exists today. This should be addressed by creating a category of expenses for which the utility can earn a return to recognize its opportunity cost.

IX. SCALE

Important to making a utility whole through its transformation from an asset investment and management operation to an efficient platform for collaborative investment, is the issue of scale. All else being equal, the scale of the return allowed must match the scale of the utility's potential return from the investment that is being avoided, in order for the utility to consider the alternative.

[2] This calculation is a rough estimate and excludes property-related costs such as taxes and insurance.

For example, using the hypothetical $1 million distribution investment discussed above, if the utility's expected earned net return on investment is 2%, its reward might be $20,000 per year above its costs.[3] Authorizing revenue recovery of this magnitude should therefore be sufficient to make the utility neutral with respect to the DER versus its own capital improvement. Moreover, the total cost of the DER approach ($50,000 + $20,000 per year) is still far less than the depreciation and return that would be generated by the utility capital investment ($150,000 per year). Thus, a revenue requirement under the collaborative DER approach would be less than the revenue requirement for the distribution facilities, had they been installed.[4]

While the payment of a $20,000 bonus to the utility on top of incentives to customers of $50,000 may seem excessive, this is the magnitude of incentive that would be required to make the utility indifferent between the investment in distribution facilities and providing incentives for strategic DERs.

X. INCENTIVES FOR TDUS

The objective of providing rewards for achieving performance goals (and possibly symmetric negative consequences for not achieving established goals) is to move beyond the neutral posture achieved by the measures discussed above, and energize utilities to voluntarily undertake initiatives that make both utilities and their customers better off. The objective of performance based incentives is to ensure that utility executives wake up every morning thinking about how they can partner with their customers, competitive retailers and service providers, to improve service and the customer experience, while reducing total costs. We believe it is possible for utilities to earn greater returns, even greater profits, while total operating and capital costs, and customer rates, decline. This is what we would expect in a competitive environment.

There are a variety of ways to provide incentives to utilities through the regulatory process. Perhaps the alternative most commonly considered by regulators is to provide an increased rate of return for improved or exceptional performance. This approach tends to continue the focus on "input-based" cost of service regulation, however, rewarding investment unless the process has been adjusted as described in the previous section to allow returns to be earned on cost saving expenses. Also, adjusting rate of return allowed has complex impacts depending on the movement of the cost of money in the market and the value of the utility's stock relative to other investment opportunities.

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[3] While current regulated rates of return are about 9%, when the cost of capital and uncertainties inherent in rate regulation are considered, a utility's earned return would be significantly less than that.

[4] Some parties would point out that society is only better off if, in addition, the total investment, including the investment by third-parties is less than the total utility investment avoided. However, it is difficult to measure the possible additional values contributing customers may find in adopting DERs, such as security, reliability, self-reliance, resilience, improved property values, resale or salvage value, reduced environmental impact, esthetics, and so on.

Another approach is to focus instead on "output." That is incentives can be associated with performance measures designed to reflect the performance goals set for the utility previously. Regulators might simply offer predetermined earnings rewards for achieving specific goals a commission hopes to see the utility achieve. Shared savings mechanisms can provide a means to do this in a proportional way. For example, in addition to the Energy Efficiency Cost Recovery Factor through which Texas IOUs recover the program and incentive cost of customer efficiency programs, they are allowed to retain a share of the savings their programs create, so long at the program costs plus the incentive is still more cost effective than doing nothing. This is a win-win mechanism for Texas ratepayers. This kind of mechanism could certainly be expanded to cover a wider range of operational efficiencies that a utility might achieve through collaborative work with other stakeholders including consumers.

Certainly design of incentives present the same difficulties as design of a general decoupling mechanism, in that it requires regulators to clearly define goals and measures upon which incentives are rewarded, and implement it consistently. Experience is that more specific objectives and reward structures work better than more general ones which make real accountability difficult. Regulators must also take care to evaluate the real combined revenue effects of cost recovery, lost revenue and incentives to avoid over or under compensating utilities. Still, rewarding the utility for its output, its performance, seems preferable to regulators either micromanaging, or doing nothing.

XI. RATE DESIGN

Once regulators determine the appropriate level of revenues that a utility is authorized to collect, there is still the issue of how the revenue recovery is apportioned among customers. This is called rate design. As already mentioned above, today regulators rely primarily upon volumetric rates for utilities to recover costs from residential and small commercial customers. Larger commercial and industrial customers pay for TDU services in line with their total demand on the assets of the utility. The design of rates can impact both the reliability or stability or revenue recovery, and the response of electric retailers or end-use customers to the charges passed on.

Recovery of authorized revenues should occur through the application of a rate structure that complements the goals adopted for the utility's performance. It should reinforce the utility incentive for meeting goals set by regulators and stockholders, and should send appropriate price signals to the market.

XII. THE PROBLEM WITH VOLUMETRIC RATES

Collecting revenues through volumetric rates to mass market consumers fails to meet these objectives. As already noted here and in our previous reports, volumetric rates tend to make utilities concerned about increased levels of efficiency or DER adoption. In addition, increasing rates of adoption of DERs has raised new issues about cross-subsidies. Although individual consumption levels may change, costs associated with service to each customer are relatively fixed, at least in the short-term. Proliferating DER adoption therefore reduces revenue recovery by the utility, forcing it to request rate increases for all customers. Regulators nationally are struggling with the issue that this tends to shift the cost of utility infrastructure from customers who adopt DERs to those who do not, even though each may require a similar level of delivery capacity. This provides an incentive to invest in DERs on the one hand, but may amount to a cross-subsidy from other customers without the assurance that the whole system is better off or total costs are reduced. And, as many have pointed out threatens to begin a downward spiral of increasing cost to remaining customers.

XIII. ALTERNATIVE RATE OPTIONS

There are two similar rate design options that address the cost-recovery issues by trying to align the allocation of revenue recovery to customers with the investment they require:

1) recover fixed TDU costs through fixed monthly charges and variable costs through variable charges; or
2) recover fixed TDU costs through demand charges and variable costs through variable charges.

These approaches are both referred to as Straight Fixed Variable (SFV) rate design.[5]

The key advantage to a utility of these rate designs is that the utility costs that customers can avoid by adopting DERs or simply reducing their consumption are more closely related to the costs that the utility avoids by the change in customer behavior. Thus, because a typical customer with DER continues to be connected to the distribution grid and buy power over the grid, it should continue to pay its share of the costs of grid facilities.

XIV. SFV RATE DESIGN AND PRICE SIGNALS TO THE MARKET

Our primary concern with the SFV rate design approach is that it could deter customers from investing in energy efficiency or other DERs.[6] Under the predominantly variable rates that residential customers are charged today, customers can take action to control energy costs by making energy efficiency improvements, installing DG, or simply consuming less energy. Shifting cost recovery from a variable charge to a fixed charge reduces customers' ability to control costs through these options, because a larger portion of the customers' charges would be fixed, rather than variable.

This concern is largely based on proposals for adopting truly "fixed" charges that reflect the infrastructure costs associated with a customer class, which utilities argue are largely fixed. We agree that TDU costs are largely fixed in the short-term, but argue the key to appropriate application of this principle is determining what is truly fixed. Utility investments are relatively long-term, and in the long term are more variable, based upon the peak demand consumers place on the system.

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[5] Kirsch, Laurence and Mathew Morey, *Alternative Electricity Rate Mechanisms Adopted by Other States*, at v (May 2016)(report prepared for the Public Utility Commission of Texas by Christensen Associates Energy Consulting).

[6] This is the flip side of the argument that volumetric rates are creating cross subsidies, or inappropriately shifting rate burden.

Purely volume-based rate designs encourage reduction in total consumption, but ignore the value of reducing peak demand, the primary factor behind the long-run requirement for utility investment. If we consider which costs are variable in the long-term, and adopt the second option for SFV rates described above, we can send a meaningful price signal to manage or reduce peak demand. That is, if we assign the majority of ERCOT TDU costs in proportion to a customer's coincident-peak demand,[7] this still enables a consumer to impact its costs through appropriate investments. And, such a price signal would tend to encourage DER investments that would be more likely to help the utility avoid compensating investments.

Texas has the benefit of having already deployed AMI infrastructure to every customer in the IOU territories of ERCOT. This would in fact enable an approximated demand charge system, even for smaller customers, to cover the TDU portion of customer rates. Our suggestion here is that all customers receive a TDU charge that is largely based on that customer's contribution to peak demand. There is some concern that a true coincident peak charge would have unintended negative consequences in the energy market, and for small customers it would be unknown until after the fact. The most appropriate resolution of these competing concerns could be to have the TDU charge reflect a time-of-use related charge, based on the peak of the previous year. So this might boil down to a TDU charge per kW, based on demand in a predetermined peak window, like 4:00 PM to 7:00 PM on summer weekdays. The beauty of this approach is that if the accelerating adoption of DERs, including efficiency and energy management systems, begins to shift the peak period, as it has in Hawaii and California for example, the window used to determine the peak charge can automatically shift as well.

Competitive retail electric providers would still layer on top of this peak demand charge their own charges for retail services and energy. If retailers simply pass on TDU charges, as most do today, this could result in a combined rate structure reflecting the long-run cost of delivery infrastructure, and the cost of energy consumption. Customers would be incented to not only reduce consumption, but reduce coincident peak demand. This would help improve the overall utilization of the utility assets already constructed, and avoid unnecessary new revenue requirements. And, it would provide more appropriate incentives for the adoption of peak shifting or peak reduction investments in distributed generation, and energy storage, as well as improved building envelop measures that allow climate systems to be downsized.

Because the TDU actually bills the retail electric provider (REP), not the consumer directly, the REP could also choose to undertake actions to reduce its total costs or reduce its exposure to TDU charges. It need not simply pass on the TDU charge as a line item. Viewed in aggregate, a TDU charge based on the total demand of a REP's customers could lead the REP to view the charge as something not entirely out of its control. It could offer programs more readily understandable, and actionable by its customers, like peak load management incentives, or programs for efficiency or demand response, onsite storage, or

[7] The hour or 15 minute increment of peak demand on the entire utility or ERCOT system.

generation, to impact its overall TDU charge. It could improve its own competitiveness by reducing peak costs.

XV. SFV Impact on Low Income Customers

SFV rate design represents a significant change in rate design, and could result in higher delivery charges for low-consumption customers. This would be particularly true, if the mechanism relies upon truly "fixed" charge. However, if the SFV were to shift to peak capacity-based charges for distribution services this would be moderated; smaller users tend to have smaller peak demand, and low-cost energy management (including behavioral changes) could be employed to avoid or reduce demand near system peak by all customers. Although coincident peak charges cannot be perfectly foretold, Texas peak consumption is remarkably predictable. In addition, truly coincident peak rates might be replaced with a peak charged based on a set time window, based on this historical information. All consumers would have the option to avoid coincident peak charges as well as energy charges through individual action.

XVI. Conclusions and Recommendations

The evolution of energy and information technologies and the changing expectations of customers, are forcing the reconsideration of the role of the transmission and distribution utility. Traditional utility cost of service regulation and through-put based rates made sense during an era when our policy goal was the buildout of the electric grid to meet growth in demand that doubled nearly every decade. Because of innovations in efficiency and distributed resources at increasingly smaller scale, the rate of growth in electric demand on utilities is no longer directly linked to the growth in population or the economy. The current rate structure makes these changes threatening to utilities, whereas, under a different regulatory structure, they might be viewed as new tools in the utility's tool shed.

While Texas has not experienced change as dramatically as some states, in part because of the robust competition we have fostered, the state should both continue to remove barriers to competitive forces driving innovation in the market, and should begin now to consider how our regulatory structure might better serve the needs of the state in the future. We suggest that:

1) Adjusting the utility revenue recovery process to acknowledge the changing circumstance utilities find themselves in today, particularly for the IOUs in the competitive market, is appropriate but complex. The PUCT should request sufficient flexibility from the legislature to begin an investigation in earnest to further evaluate, and adopt as appropriate, alternative ratemaking for utilities in its jurisdiction to maintain the financial health of the utilities while encouraging and enabling innovation, including increased integration of efficiency and other DERs to achieve continuous operational improvement and affordability.
2) We find appropriate solutions will include four elements generally:
    a. Clear goals to empower customer choice of technologies and services, including improved access to AMI data, improve operational reliability and efficiency, and increase utilization of existing assets, achieve environmental sustainability, and animate market innovation.

b. Cost recovery for expenditures made to cost-effectively meet public goals,
c. Measures to make each utility financially neutral toward lost revenues and lost opportunity costs so long as total costs decline *per capita*, and
d. Incentives for utilities to mimic the innovation behavior of competitive firms.

3) The PUCT should adopt transmission and distribution rates that include small fixed charges for truly fixed costs and, that allocate the majority of costs, even for residential and small commercial customers, on the basis of customer coincident peak demand. This recognizes capacity requirements as long-run variable costs, contributes to stable revenue requirements even as consumers become more efficient or become energy producers, and sends a price signal to consumers to invest in modifying peak demand in ways that benefit all ratepayers and society generally.