Curating the Future of Rate Design for Residential Customers

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By Ahmad Faruqui and Wade Davis, with Josephine Duh and Cody Warner

Electricity Policy – the website ElectricityPolicy.com and the newsletter Electricity Daily – together comprise an essential source of information about the forces driving change in the electric power industry.

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In 2014, 87 percent of all electric utility customers in the U.S. were residential customers, some 129 million out of 147 million. While the typical residential customer uses a lot less energy than the typical non-residential customer, in the aggregate residential customers account for almost four-tenths of the electricity that is consumed in the country.[1] And since residential customers have lower load factors than non-residential customers, residential customers' share of peak load is probably higher than

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The paper has benefited enormously from comments from Brattle principals and external reviewers. We are indebted to all of them but the views expressed in this paper are entirely our own and not of the reviewers or of The Brattle Group.

[1] Table 1.2. Summary Statistics for the United States, 2004 - 2014. (2016, February 16). U.S. Energy Information Administration. Retrieved June 13, 2016, from:

http://www.eia.gov/electricity/annual/html/epa_01_02.html.

four-tenths. Considering emerging trends and advancing technologies, it is more important than ever to price electricity correctly for residential customers.

For more than a century, residential customers have paid for electricity through two-part rates: a monthly service fee (or fixed charge) and a volumetric charge expressed in cents per kilowatt hour (kWh) of energy consumed. The fixed charge has typically not varied across residential customers regardless of the size of their monthly usage or the type of service the customer takes (e.g., 3-phase). Over time, fixed charges have become a very small share of the typical customer's bill.[2] *Under these rate structures, larger users have paid larger bills than smaller users, regardless of customers' peak demand. The two-part rate structure may look fair and efficient on the surface, but it is neither. Transitioning residential customers to three-part rates, including a monthly fixed charge, volumetric charge, and demand charge, could resolve many of the problematic equity and efficiency concerns intrinsic to a two-part rate.*

I. The Problem: Cross-subsidies and Misalignment

While the bulk of utility revenue[3] from residential customers has come from the volumetric charge, the majority of utility costs do not vary with the volume of electricity that is consumed. A larger share of a utility's costs are either fixed or a function of customers' instantaneous demands, measured in kilowatts (expressed in kW as opposed to energy usage, or kWh). So the structure of electric rates (i.e., revenues) and the nature of a utility's infrastructure and other costs have been misaligned.[4] **Figure 1** typifies this misalignment. There have been two consequences of this misalignment: economic inefficiency and inequity.[5] The former has meant that residential customers have imposed a larger demand on the capacity of the power system than would have been the case had they seen a price signal for their use of capacity. Thus, it costs more to provide electricity to residential customers than it would have otherwise cost

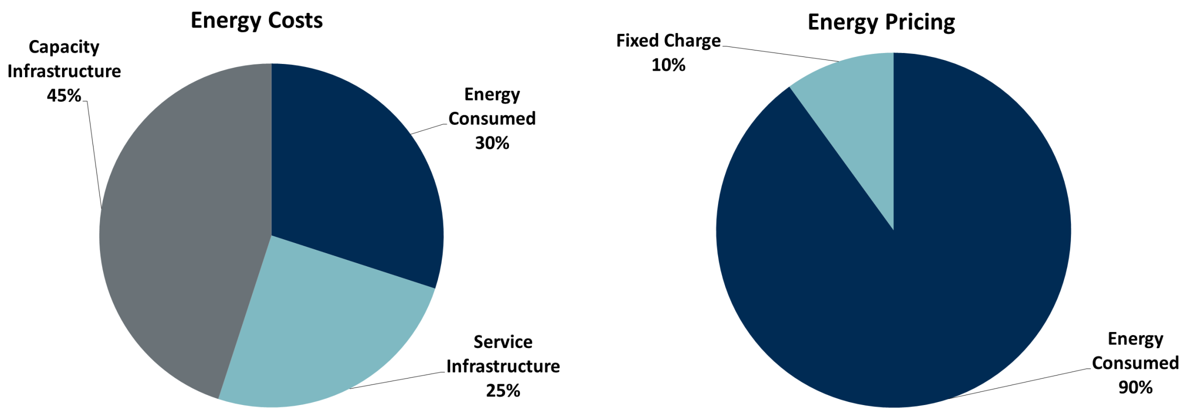
[2] This condition can be exacerbated because a low customer charge may allow a regulatory commission to manage and limit a visible component of the rate to match policy goals, such as protecting at-risk customers. Historically, utilities have accepted this status quo since growth in usage provided a buffer for the mismatch with cost causation. In some jurisdictions, the customer charge has become the symbol of the residential rate where perception of value is tied to it more than to the volumetric rate.

[3] Here, revenue refers to revenue related to utilities' distribution and transmission processes. Fuel and purchased power costs for energy only are variable and not the focus of discussion in this article.

[4] This misalignment has generally not been the case for tariffs that have been charged to medium and large commercial and industrial customers. They have had three-part rate structures in place for many decades. However, misalignment exists for some commercial and industrial (C&I) customers.

[5] Another consequence was to increase the sensitivity of the utility to volumetric sales. Traditional ratemaking includes an inherent reliance on sales, but the choice to misalign the costs has placed many utilities in a tenuous position.

Figure 1: The Mismatch Between Energy Costs and Energy Pricing: An Illustrative Example from a Southwestern Utility[6]



The latter has meant that cross-subsidies have been created even between residential customers, with smaller residential customers often being subsidized by larger residential customers.

An additional misalignment occurs since the cost of supplying electricity typically varies by time-of-day and across the seasons. The volumetric charge in most residential tariffs has tended to be flat and has masked this temporal variation in costs. Thus, customers have over-consumed electricity during the relatively expensive peak periods and under-consumed it during the relatively less expensive off-peak periods. This has created additional economic inefficiencies and additional inequities.

A. A Cross Subsidy Example

The mismatch between utilities' cost structures and their largely volumetric-based rate structures creates an inevitable and indisputable cost shift from customers with lower load factors to customers with higher load factors. This higher load factor customer imposes a lower cost on the grid and provides a cross-subsidy to the customer with the lower load factor. Customers might reduce their load factor if, for instance, they install rooftop solar that produces energy during the day. With a lower load factor, customers paying for electricity under a flat volumetric rate design will reduce their bill without providing a proportionate reduction in fixed infrastructure costs they impose on the system. Customers with higher load factors, who are paying for electric service under a volumetric rate design, wind up paying more for comparable service.

6 Lockwood, Barbara. (2015). Residential Demand Charges. Presentation at NARUC Annual Meeting.

To illustrate this point, we present a simple example constructed around a fictional utility, Smart Power & Light.[7] The example shows how two-part rates create cross-subsidies between customer classes. Smart Power & Light is authorized to collect $120 million in revenue per year from the 100,000 households in its service area. There are three types of households: low-usage households consume 500 kWh/month, standard-usage households consume 1,000 kWh/month, and high-usage households consume 1,500 kWh/month. This is shown in **Table 1**.

Table 1: Characteristics of Smart Power & Light

Input	Value	Units
Revenue Requirement	120,000,000	($/yr)
Households	100,000	(households)
Average Usage		
Low-users	500	(kWh/mo)
Standard-users	1,000	(kWh/mo)
High-users	1,500	(kWh/mo)
Load Factor		
Low-users	23%	%
Standard-users	27%	%
High-users	29%	%

Smart Power & Light collects its revenue requirement from customers with a two-part rate. Under its two-part rate, the utility collects ten percent of its revenue requirement with a fixed charge and ninety percent with a variable energy charge. However, the structure of Smart Power & Light's costs differs from its revenues. Fixed costs account for 25 percent of Smart Power & Light's total costs, variable costs account for 25 percent, and demand-related costs account for 50 percent. **Table 2** summarizes this common misalignment of costs and rates, using representative data from the industry.[8]

Table 3 illustrates how Smart Power & Light's two-part rate structure can create a cross-subsidy when households vary in use. In this example, low-usage customers, who are also low load factor customers, are subsidized by high-usage customers, who are also high load factor customers. Low-usage customers benefit from a cross-subsidy because the revenue from their low monthly usage does not compensate for the fixed costs and demand-related costs

7 This example was developed by Cody Warner.

8 Low-usage customers' maximum demand is assumed to be 3.00 kW, standard-usage maximum demand is assumed to be 5.00 kW, and high-usage maximum demand is assumed to be 7.00 kW.

required to serve them. As a result, the high-usage and high load factor customers in this example are on the hook for the subsidies to low-usage customers.

Table 2: Revenue and Cost Structure for Smart Power & Light (Including Demand)

	Revenue Structure	Cost Structure	Rate
Fixed	10%	25%	$10/mo
Variable	90%	25%	$0.09/kWh
Demand	0%	50%	-

Table 3: Illustration of Cross-Subsidization Under a Two-Part Rate at Smart Power & Light (Including Demand)

Customer Class	Monthly Usage (kWh)	Demand (kW)	Load Factor	Fixed ($/mo)	Variable ($/mo)	Demand ($/mo)	Monthly Bill ($/mo)	Yearly Bill ($/yr)	Number of Households	Total to Utility ($/yr)
Standard household	**1,000**	**5.00**	**27%**						**33,333**	
Revenue				10	90	-	100	1,200		40,000,000
Cost				25	25	50	100	1,200		40,000,000
Over (Under) Payment				(15)	65	(50)	-	-		-
Low-usage household	**500**	**3.00**	**23%**						**33,333**	
Revenue				10	45	-	55	660		22,000,000
Cost				25	13	30	68	810		27,000,000
Over (Under) Payment				(15)	33	(30)	**(13)**	(150)		**(5,000,000)**
High-usage household	**1,500**	**7.00**	**29%**						**33,333**	
Revenue				10	135	-	145	1,740		58,000,000
Cost				25	38	70	133	1,590		53,000,000
Over (Under) Payment				(15)	98	(70)	**13**	150		**5,000,000**
Total				**(45)**	**195**	**(150)**	**-**	**-**	**100,000**	**120,000,000**

II. A Solution: Three-Part Rates

The misalignments between fixed and variable costs in current two-part rates violate a fundamental tenet of rate design – cost causation. According to the notion of cost causation, a rate structure should reflect the nature of the costs incurred to provide the service. To address the deficiencies of current two-part residential rates, some utilities are proposing the institution of a three-part rate design, consisting of a monthly service charge, a demand charge, and a volumetric charge.

The fixed charge may be designed to cover the fixed costs such as metering, billing, and customer care. It may also be appropriate to reflect the cost of the line drop and the associated transformer.

The demand charge may be designed to cover demand-driven costs, such as transmission, distribution, and generation capacity. Such a demand charge would typically be applied to the individual customer's maximum demand, either during a defined on-peak period, or regardless of time of occurrence, or based on a combination of the two. While the concept of demand is instantaneous, in implementation demand is usually measured over 15-minute, 30-minute or 60-minute intervals.

The volumetric charge covers variable power grid operations and maintenance (O&M) cost, the cost of the fuels that are used to generate electricity, like coal and natural gas, as well as purchased power expenses. The demand charge and the volumetric charge might vary with the time of use of electricity and have different seasonal and/or on-peak/off-peak levels. Customers have shown a high level of price responsiveness to time-varying rates, which can be used to promote a more efficient, less expensive electricity grid. Three-part rates with time-varying components better align the rates with underlying fixed and variable costs, a fundamental tenet of rate design.[9]

A. Bonbright and the Development of Three-Part Rates

The principles that guide rate design and support the three-part rate have evolved over time. Many authorities have contributed to their development, beginning with the legendary British rate engineer John Hopkinson in the late 1800s.[10] Hopkinson introduced demand charges into electricity rates. Not long after, Henry L. Doherty proposed a three-part tariff, consisting of a fixed service charge, a demand charge and an energy charge.[11] The demand charge was based on the maximum level of demand which occurred during the billing period. Some versions of the three-part tariff also feature seasonal or time-of-use (TOU) variation corresponding to the variations in the costs of energy supply.[12]

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9 To be perfectly clear, three part rates provide a better *opportunity* to align rates with costs. Utilities or commissions could still get the pricing wrong within the three-part rate, thereby failing to correct the problem.

10 John R. Hopkinson, "On the Cost of Electricity Supply," *Transactions of the Junior Engineering Society*, Vol. 3, No. 1 (1892), pp.1-14

11 Henry L. Doherty, *Equitable, Uniform and Competitive Rates*, Proceedings of the National Electric Light Association (1900), pp.291-321

12 See, for example, Michael Veall, "Industrial Electricity Demand and the Hopkinson Rate: An Application of the Extreme Value Distribution," *Bell Journal of Economics*, Vol. 14, Issue No. 2 (1983).

In the decades that followed, a number of British, French and U.S. economists and engineers made further enhancements to the original three-part rate design.[13] In 1961, Professor James C. Bonbright coalesced their thinking in his canon, Principles of Public Utility Rates,[14] which was expanded in its second edition by two co-authors, Albert Danielsen and David Kamerschen, and published in 1988. Some of these ideas were further expanded upon by Professor Alfred Kahn in his treatise, The Economics of Regulation.[15]

The Bonbright principles are timeless. The most important concepts can be summarized in five core principles:

1. Economic efficiency- The price of electricity should convey to the customer the cost of producing and delivering it, ensuring that resources consumed in the production and delivery of electricity are not wasted. If the price is set equal to the cost of providing a kWh, customers who value the kWh more than the cost of producing it will use the kWh and customers who do not, will not. This will encourage the development and adoption of energy technologies that are capable of providing the most valuable services to the power grid.

2. Equity- There should be no unintentional subsidies between customer types. A classic example of the violation of this principle occurs under flat volumetric pricing (i.e., fixed cents/kWh, regardless of time-of-day or season). Since customers have different load profiles, "peaky" customers, who use more electricity when it is most expensive, are subsidized by less "peaky" customers who overpay for cheaper off-peak electricity. Note that equity is not the same as social justice, which is related to inequities in socioeconomic conditions rather than cost. The pursuit of one is not necessarily the pursuit of the other.

3. Revenue adequacy and stability- Rates should recover the authorized revenues of the utility and should promote revenue stability. Theoretically, all rate designs can be implemented to be revenue neutral within a class, but this would require perfect foresight of the future. Changing technologies and customer behaviors make load forecasting more difficult and increase the risk of the utility either under-recovering or over-recovering costs when rates are not cost reflective. As utilities are highly capitally intensive and must raise significant amounts of financial capital, revenue stability reduces borrowing costs, ultimately reducing costs to customers.

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13 The most notable names include Maurice Allais, Marcel Boiteux, Douglas J. Bolton, Ronald Coase, Jules Dupuit, Harold Hotelling, Henrik Houthakker, W. Arthur Lewis, I. M. D. Little, James Meade, Peter Steiner and Ralph Turvey.

14 James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, *Principles of Public Utility Rates*, 2d ed. (Arlington, VA: Public Utility Reports, 1988).

15 Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, rev. ed. (MIT Press, June 1988).

4. Bill stability- Customer bills should be stable and predictable while striking a balance with the other ratemaking principles.[16] Rates that are not cost reflective will tend to be less stable over time, since both costs and loads are changing. For example, if fixed infrastructure costs are spread over a certain number of kWh in Year 1, and the number of kWh halves in Year 2, then the price per kWh in Year 2 will double even though there is no change in the underlying infrastructure and other fixed costs of the utility. This is important because, just as utilities invest to meet customer needs, customers invest in response to prices and neither wish to have the value of their investments degraded.
5. Customer understandability- Rates should enhance customer understandability.[17] Because most residential customers devote relatively little time to reading their electric bills, rates need to be relatively simple so that customers can understand them and perhaps respond to them by modifying their energy use patterns. Giving customers meaningful cost-reflective rate choices helps enhance customer understandability.

The importance of economic efficiency – and specifically on designing rates that reflect costs - is emphasized by Bonbright. In the first edition of his text, Bonbright devotes an entire chapter to cost causation. In the chapter, he states: "One standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and public opinion alike – the standard of cost of service, often qualified by the stipulation that the relevant cost is necessary cost or cost reasonably or prudently incurred."[18] Later, he states "The first support for the cost-price standard is concerned with the consumer-rationing function when performed under the principle of consumer sovereignty."[19] He also cites another benefit of the cost-price standard, saying that "an individual with a given income who decides to draw upon the producer, and hence on society, for a supply of public utility services should be made to 'account' for this draft by the surrender of a cost-equivalent opportunity to use his cash income for the purchase of other things."[20]

Later in the text, where he discusses the "criteria of a sound rate structure," Bonbright argues that a purely volumetric rate assumes that the total costs of the utility vary directly with the changes in the kWh output of energy. He calls this "a grossly false assumption" and says such a rate "violates the most widely accepted canon of fair pricing, the principle of service at cost."

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16 Bill stability is closely related to revenue stability (#2). Poor rate designs exacerbated by low growth may put utilities in a catch-up position requiring continuous rate cases. The frequent rate case activity can undermine perceived stability incorporated in the rate design.

17 When the customer understands the rate, they will have more knowledge about the cost of electricity, which may lead to customer satisfaction or at least acceptance.

18 James C. Bonbright, *Principles of Public Utility Rates*, (Columbia University Press: 1961) 1st Edition, Chapter IV, p. 67.

19 Op. cit., p. 69.

20 Op. cit., p. 70.

Later, while discussing the Hopkinson rate, he says that such a "rate distinguishes between the two most important cost functions of an electric-utility system: between those costs that vary with changes in the system's output of energy, and those costs that vary with plant capacity and hence with the maximum demands on the system (and subsystems) that the company must be prepared to meet in planning its construction program."[21]

According to his widely cited text, Bonbright believed that three-part rates mirrored the structure of utility costs and cited their widespread deployment to medium and large commercial and industrial rates.[22] In support of three-part rates, Bonbright cites an earlier text by the British engineer D. J. Bolton,[23] who states:

> "*More accurate costing has shown that, on the average, only one-quarter of the total costs of electricity supply are represented by coal*[24] *or items proportional to energy, while three-quarters are represented by fixed costs or items proportional to power, etc. If therefore only one rate is to be levied it would appear more logical to charge for power and neglect the energy, were it not for certain practical difficulties of which the following are two. In the first place the effective power demand on the system made by any particular consumer is extremely difficult to estimate, and is very different from the individual maximum demand metered at the consumer's terminals. Secondly, a purely power tariff would probably lead to a waste of energy to a greater extent than a purely energy tariff leads to waste of power.*"[25]

Of course, with the arrival of smart meters, customer demand at times of system and distribution peak can be accurately recorded. And the choice is no longer a binary one of imposing either a demand-only rate or an energy-only rate. Interestingly, when Bonbright discusses a two-part rate structure, he is referring to what he characterizes as "the two most important cost functions of an electric-utility system"[26] – demand and energy charges. When he

21 Op. cit., p. 310.

22 James C. Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961.

23 Bonbright says, "On many technical issues, no American treatise on electric utility rates can equal that by the distinguished British rate engineer D. J. Bolton." Page 289, n. 3.

24 Coal was the dominant fuel for generating electricity in the United Kingdom in 1938 when the book was first published.

25 D. J. Bolton, *Electrical Engineering Economics. Volume Two: Costs and Tariffs in Electricity Supply, Second Edition, Revised* (London: Chapman & Hall Ltd., 1951) p. 59. At p. 40, in Chapter III, Marginal Cost and the Price Structure," he notes "A more precise method (to measure costs) is to enlarge the whole conception of output. Instead of regarding output as measured in kWh, and the other factors (kW of demand, etc.) as merely varying attributes of the kWh, it is better to treat them quantitatively and regard them as separate sorts of output in their own right. Just as kWh costs can be isolated and hence allocated according to the measured kWh of the customer, so the kW costs can be isolated and allocated according to the customer's estimated or measured peak demand."

26 Bonbright, p. 310.

moves into a discussion of three-part rate structures, he adds truly fixed charges, customer charges, to the two-part rate concept.[27]

B. Three-Part Rates Can Achieve Efficiency and Integration of New Technology

By providing customers with a price signal that includes components for demand time-varying energy consumption, a three-part rate would encourage the adoption of behaviors and technologies that smooth out a customer's load profile or match consumption with intermittent supply. These changes in energy consumption will lead to more efficient overall use of electricity grid infrastructure and resources. Demand charges allow utilities to signal when and where there are supply or distribution constraints. Similarly, time-varying volumetric rates allow utilities to signal when generation and distribution are least expensive. These price signals could facilitate a smarter energy grid by encouraging optimum usage when inexpensive renewable energy is available and lower usage when only expensive, environmentally harmful fossil fuel generation is available.

A more cost-reflective rate can also foster the adoption of emerging energy technologies, like battery storage, programmable appliances, and rooftop solar. Behind-the-meter battery storage could be used to release electricity during hours of high electricity demand and store electricity during hours of low electricity demand. Load control technologies, such as programmable communicating thermostats, demand limiters, and smart appliances could also help customers better manage their electricity demand. While there is a cost associated with these enabling technologies, they provide levers of change that could help make customers more accepting of the new rate design. If a customer took service under a three-part rate, the use of battery storage or other demand-reducing technologies would reduce the customer's bill. This reduction in the customer's bill is an economic value that forms the basis of the price signal created by three-part rates.

Three-part rates can also incentivize customers to smooth their energy consumption profile even if they have not yet installed enabling technologies. As discussed in the next section, more than 50 pilot studies and full-scale rate deployments involving over 200 rate offerings have found that customers do actually respond to new price signals by changing their energy consumption patterns.[28]

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27 Bonbright, second edition, page 401, credits Doherty with extending the Hopkinson two-part rate into a three-part rate. Henry L. Doherty, "Equitable, Uniform and Competitive Rates," Proceedings of the National Electric Light Association, 1900, pp. 291-321.

28 Some of these studies are summarized in Ahmad Faruqui and Sanem Sergici, "Arcturus: International Evidence on Dynamic Pricing," *The Electricity Journal*, (August/September 2013). Similar results were obtained from an earlier generation of 14

Continued on next page

Further, there is some evidence that customers respond not just to changes in the rate structure generally, but specifically to demand charges. There are at least four studies that reach this conclusion, estimating peak period consumption reductions between 5 and 41 percent.[29]

We also have some recent evidence from Arizona that customers respond to demand charges. Arizona Public Service Company (APS) has reported that 60 percent of a sample of APS customers on a three-part rate reduced their demand after switching to the three-part rate, with those who actively manage their demand achieving savings of 10 percent to 20 percent or more.[30]

Brattle has developed a model for simulating the impact of demand charges, building on our earlier work for simulating customer price response to dynamic pricing tariffs and to inclining block rates.[31]

C. Empirical Evidence on Time-Varying Rates

As an increasing number of electric utilities have begun offering time-varying rates to residential customers, The Brattle Group has maintained the *Arcturus* database tracking each rate's impacts on peak period electricity consumption.[32] The increasing interest in time-varying rates is largely enabled by the deployment of smart meters, which facilitate more complex rate designs. In addition to better aligning pricing and costs, time-varying electricity rates can also

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pricing pilots that were funded in the late seventies and early eighties by the US Federal Energy Administration (later part of the Department of Energy. here were also early studies producing similar results. See Ahmad Faruqui and Bob Malko, "The Residential Demand for Electricity by Time-of-Use: A Survey of Twelve Experiments with Peak Load Pricing," Energy, Vol. 8, No. 10, (1983).

29 Caves, D., Christensen, L., Herriges, J., 1984. "Modeling alternative residential peak-load electricity rate structures." *J. Econometrics*. 24(3), 249-268.

Stokke, A., Doorman, G., Ericson, T., 2009, January. "An Analysis of a Demand Charge Electricity Grid Tariff in the Residential Sector," Discussion Paper 574, Statistics Norway Research Department.

Taylor, Thomas N., 1982. "Time-of-Day Pricing with a Demand Charge: Three-Year Results for a Summer Peak." Award Papers in Public Utility Economics and Regulation. Institute of Public Utilities, Michigan State University, East Lansing, Michigan.

Taylor, T., Schwartz, P., 1986, April. "A residential demand charge: evidence from the Duke Power time-of-day pricing experiment." *Energy Journal*. 7(2), 135–151.

30 Direct Testimony of Charles A. Miessner on Behalf of Arizona Public Service Company. Docket No. E-01345A-16-0036. June 1, 2016. Part 3 of Arizona Public Service Company Rate Application. pp. 20. Available at: http://edocket.azcc.gov/Docket/DocketDetailSearch?docketId=19348

31 Reference the PRISM suite of models.

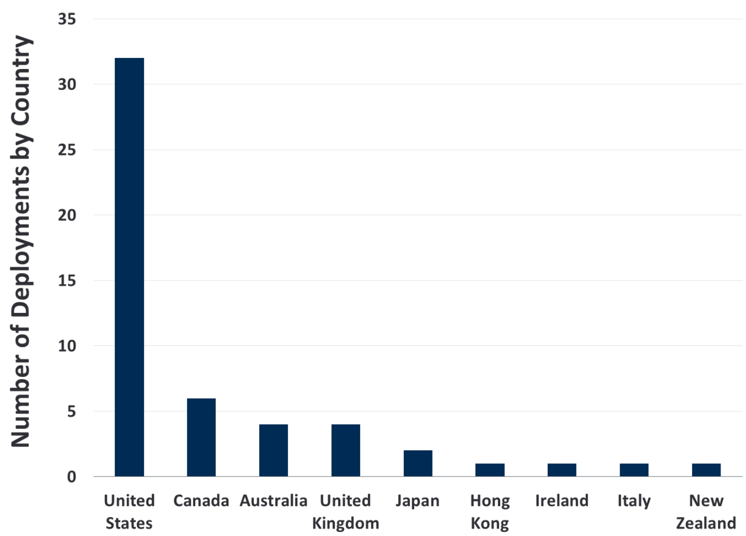
32 Findings from the Arcturus database were most recently published here:

Faruqui, A., & Sergici, S. (2014). Arcturus: An International Repository of Evidence on Dynamic Pricing. In *Smart Grid Applications and Developments* (pp. 59-74). Springer London.

incentivize customers to change consumption patterns, which can help utilities achieve lower generation and distribution costs as well as renewable energy integration.

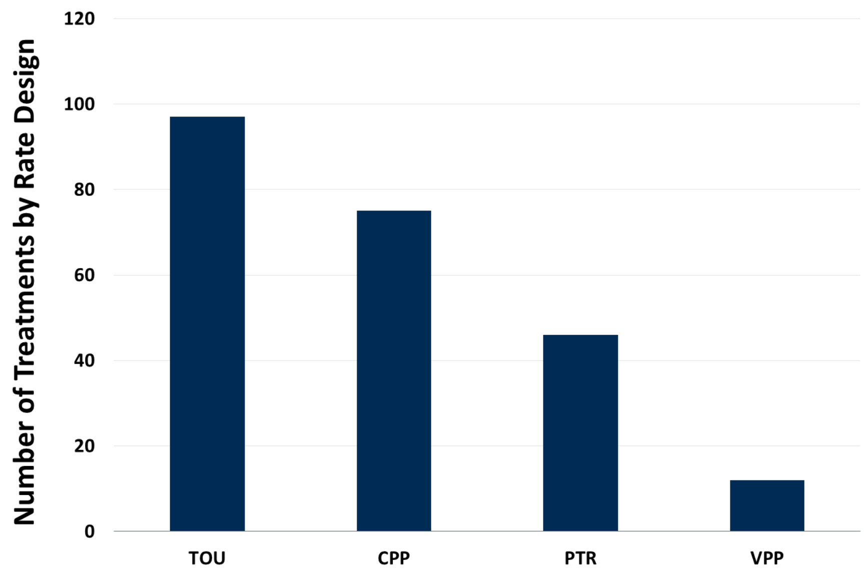
The *Arcturus* database contains over 50 deployments of time-varying deployments comprising multiple rate offerings across nine countries and four continents. Most of the deployments are either short-term pricing pilots or opt-in rates, but utilities have rolled out time-of-use rates as the default residential rate in Ontario and Italy. In total, the database includes 230 distinct pricing treatments, reflecting the fact that some utilities in these deployments chose to vary the rate options or other experiment characteristics across multiple treatment groups. **Figure 2** shows the range of geographies and rate designs included in *Arcturus*.

Figure 2: Geography of the *Arcturus* Pilots



The four rate designs tracked in the database include time-of-use pricing, critical peak pricing (CPP), peak time rebates (PTR), and variable peak pricing (VPP). **Figure 3** shows the range of rate designs represented in *Arcturus*. TOU pricing refers to a rate that includes a defined peak period with a higher volumetric price and an off-peak period with a lower volumetric price. For example, a peak period price might be $0.20/kWh from 4PM to 8PM on non-holiday weekdays, while the off-peak price would be $0.10/kWh at all other hours. Assuming that there are no other components of the rate design, the peak-to-off-peak price ratio in this example would be two to one. Variations of TOU rates may have additional periods with other prices, sometimes called shoulder, mid-peak, super on-peak, or super off-peak periods. In contrast to TOU, CPP rates only take effect on specific peak days. For example, a utility may send customers text messages before the ten hottest days of the summer to alert them that their electricity prices will be six times higher from 12PM to 10PM on those days. VPP rates are very similar to CPP rates except that prices may vary across days depending on market conditions. PTR rates are also similar to CPP rates except that customers receive a rebate for the electricity savings on the peak days, rather than paying a higher price for electricity. While PTRs are often palatable to consumer advocacy groups, PTRs can be problematic because they require utilities to estimate what each customer's electricity usage would have been absent the PTR incentive.

Figure 3: The Range of Rate Designs in *Arcturus*



The *Arcturus* database is primarily intended to determine the relationship between the peak-to-off-peak price ratio and the change in peak period electricity consumption. In addition to price ratio, peak period impact, and rate design associated with each pricing treatment, *Arcturus* also tracks the presence of enabling technologies, such as web portals, in-home displays, energy orbs, and programmable thermostats. **Figure 4** shows the diversity of peak period impacts under various pricing treatments (only those treatments that are designed to capture price responsiveness are included). Figure 5 includes the impacts from *Arcturus* treatments that include some form of enabling technology, which could potentially enhance customer responsiveness.

Using the *Arcturus* database, we regress peak period impact in percentage terms on the natural log peak-to off price ratio. We will allow the impact of the ratio to be different in the presence of enabling technology. To prevent our results from being skewed by outliers, we

Figure 4: Peak Period Impacts in *Arcturus*, Price Only

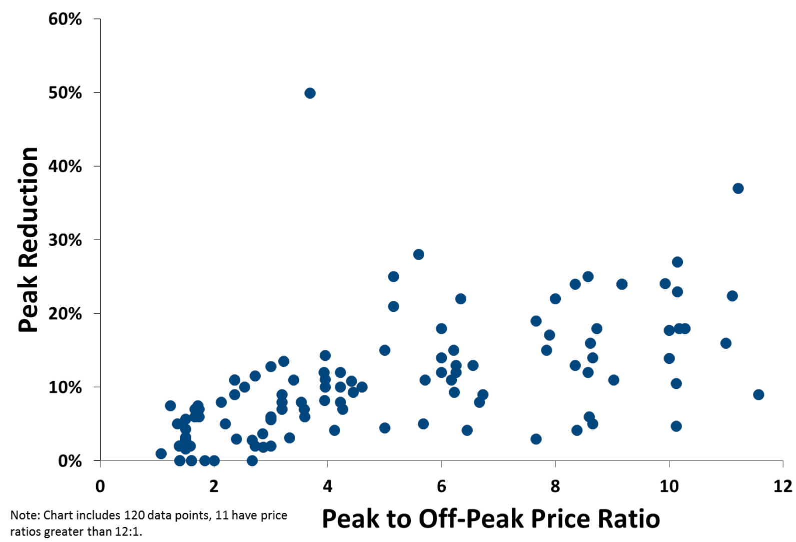
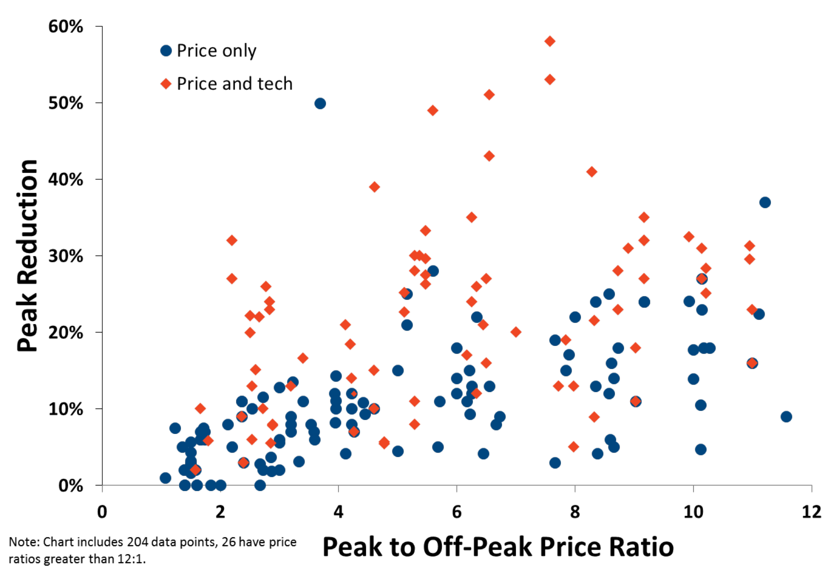


Figure 5: Peak Period Impacts in *Arcturus*, All



remove any observations with a price ratio greater than 35 to one. We also use a robustness algorithm to down-weight any additional outlier observations.[33] Of the 230 treatment impacts, a total of four observations were removed from the sample, and 214 observations were assigned weights less than one. Under this specification, we observe a strong relationship between peak reduction and price ratio with diminishing increases in price responsiveness at higher price ratios. Hence, the effect is an arc of price responsiveness. Enabling technology generally enhances the price response.

Table 4 shows the results using our robust approach and also using conventional ordinary least squares (OLS). The second model with OLS does not remove any outliers or weight any of the data, so all 230 *Arcturus* treatments are given equal consideration. The estimated relationships using the robust specification and OLS are similarly strong. **Figure 6** shows the arcs of price responsiveness that result when peak period impacts are estimated at various peak-to-off-peak price ratios. Figure 6 uses the coefficients estimated under the robust approach.

Table 4: Impact of the Peak-to-Off-Peak Price Ratio on Peak Period Consumption

	Model 1: Robust		Model 2: OLS	
	Estimate	Standard Error	Estimate	Standard Error
No enabling technology	0.062**	0.008	0.050**	0.009
With enabling technology	0.107**	0.010	0.096**	0.008

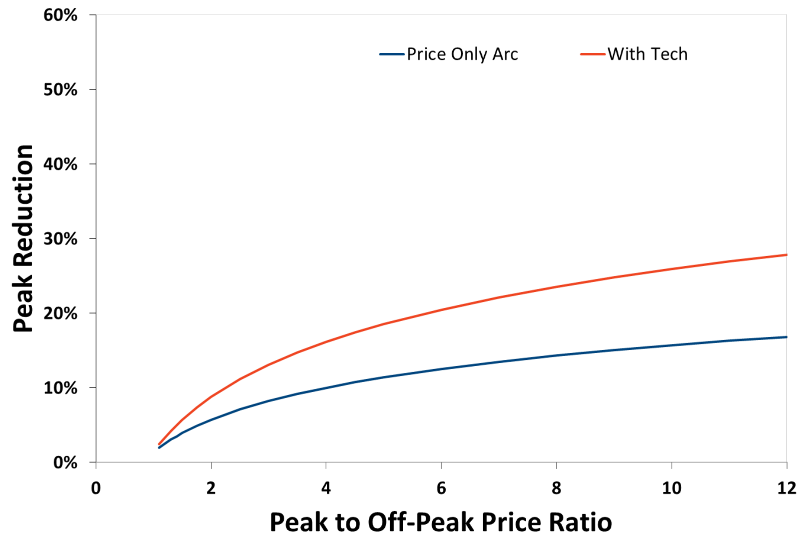
** indicates $p < 0.01$
* indicates $p < 0.05$

[33] We rely on the R package, robustbase:

Peter Rousseeuw, Christophe Croux, et al. (2015). robustbase: Basic Robust Statistics. http://CRAN.R-project.org/package=robustbase

R Core Team (2015). R: A language and environment for statistical computing. R Foundation for Statistical Computing, Vienna, Austria. https://www.R-project.org/

Figure 6: The Arcs of Price Responsiveness



III. Three-Part Rates in Practice

Based on a survey at The Brattle Group, there are at least 30 utilities in seventeen states that offer a three-part rate to residential customers.[34] APS has the most highly subscribed residential three-part rate in the U.S., with nearly 120,000 of its customers enrolled. In most cases, the rates are available to all customers on an opt-in basis. In the case of Salt River Project (SRP), a three-part rate is now mandatory for all residential customers who choose to install a new grid-connected distributed generation (DG) photovoltaic (PV) system after January 1, 2015.[35] [36] Mid-Carolina Electric Cooperative and Butler Rural Electric Cooperative include demand charges as a mandatory feature of their residential rate offering. The Brattle Group survey also found that at least five U.S. utilities offer summer season peak demand charges in residential rates. **Figure 7** (Page 25) provides details on these rates.

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34 The Brattle Group survey was conducted in April 2016.

35 SRP website. http://www.srpnet.com/prices/home/customergenerated.aspx.

36 Peak demand management could be another driver. Although many three-part rates are driven by DG, it is not the only motivation behind the rate. In Maryland and Missouri where utilities' ability to design rates specifically for DG is restricted, the focus is on the demand management benefit.

IV. The Future of Three-Part Rates

Until recently, metering technology for residential customers has been a significant limiting factor for cost-based rate designs. Also, the need for three-part rates has only recently become apparent as a result of slow sales growth, capacity limitations, and increased DG penetration. Further, there is little political appetite for rate reform, there are billing system limitations, and some pilot programs have performed poorly, often due to poor pilot design or execution. The traditional electromechanical meters that most customers had installed at their homes measured only cumulative electricity consumption in a given month and not demand. Installing the same type of interval-recording meters used by larger commercial and industrial customer would have been very cost-prohibitive. Thus, without the ability to cost-effectively meter demand, utilities decided not to offer three-part rates to these customers.[37]

With the deployment of smart meters (also referred to as advanced metering infrastructure, or AMI), both demand and energy usage can be recorded in intervals of an hour or less. This allows the utility to collect the consumption data necessary to incorporate demand charges into rates. AMI has removed a large barrier to the wider adoption of cost-reflective rates for residential customers. Rate structures for residential customers may now evolve to match the technological developments that have occurred.

A. Design Considerations With a Three-Part Rate[38]

Careful design of the rate components can alleviate concerns about the transition from a two-part rate to a more complex three-part structure. In particular, utilities and regulators must be careful to choose the appropriate split between the fixed, volumetric, and demand charges to properly align these components with costs. Rate designers will also need to choose whether or not to include seasonal and geographic variation in the rate components. For example, some regions may face more severe grid constraints that could justify higher demand charges. Further, utilities will need to choose the appropriate time-varying volumetric rate design, such as time-of-use or a dynamic rate that alerts customers to price changes via text messages or a web portal. As utilities design these more complex rate structures, they will need to balance their desire to ensure revenue stability and send correct price signals against customers' need to understand their rates and have the opportunity to respond to the given prices.

37 Utilities could have offered residential customers the same types of meters offered to some C&I customers, which do have demand measurement capabilities. However, developing this infrastructure was generally not considered economic for residential customers.

38 This section is adapted from the presentation: Hledik, R. (May 14, 2015). The Top 10 Questions about Demand Charges. Presented to EUCI Residential Demand Charges Symposium.

Choosing a definition for demand can become a stumbling block in designing a three-part rate, but it does need to be one if utilities think carefully about the intent of the demand charge and the inherent tradeoffs. For instance, utilities and regulators may choose among demand charges that target the system coincident peak, class coincident peak, local distribution peak, or some other constraint. A utility may want the charge to convey system-level capacity costs, such as generation capacity, or they may want the charge to convey distribution-level costs, such as transformers. To achieve these signals, the utility can confine the demand measurement to a certain peak period when the constraint is most likely to occur. If a utility's system peak occurs on weekdays between 4PM and 8PM, then a utility may choose that period to measure demand if reflecting system peak costs is the demand charge's primary objective.

Alternatively, a utility may choose to bill customers for maximum demand measured at any time during the month or even over the entire year if the utility is primarily concerned with localized constraints. Another approach, requiring customers to subscribe a preset level of demand before the billing cycle or when they sign up for service, could encourage customers to engage with the concept of a demand charge early and be proactive in their demand management. An additional challenge in defining demand is choosing the interval over which demand is measured. A common choice is between maximum demand measured over a one-hour interval versus a 15-minute interval. While a 15-minute interval is more precise, customers may find more flexibility with an hourly measurement. Of course, these many variations on the definition of demand are not mutually exclusive. A utility could impose multiple demand charges, each measured using a different methodology and targeted at a different cost, thereby modifying the three-part rate into a more granular four or five-part rate. Trade-offs will have to be made between accuracy in cost reflectivity and customer understandability and acceptance.

B. Customer Understanding of Demand

Customer understandability of the demand charge is one of the most commonly raised objections to the three-part rate. Critics claim that customers are much more comfortable with the volumetric concept of the kilowatt hour than the concept of demand, expressed in kilowatts. However, we note many examples where electricity customers have almost certainly encountered the kilowatt.

It would be a rare residential customer who has not considered the concept of demand with respect to the common light bulb. When buying or installing a light bulb, a customer has to choose a bulb that will project a certain amount of light. It is then that customers encounter the power of the bulb expressed in watts, the unit of electrical power or demand. The wattage may be expressed as 40, 60, 75 or 100 watts (or their equivalent, if the bulb was a compact fluorescent or LED bulb). For three-way bulbs or halogen bulb some wattages are even higher. Thus, the unassuming light bulb makes tangible the supposedly difficult concept of electrical power expressed in watts.

Earlier in life, perhaps in a high school class, the customer would have learned the concept of a kilowatt hour, and it would have been explained with a simple example, such as: if you leave a 100-watt bulb on for an hour, then you consume 100 watt-hours, and if you leave that bulb on for 10 hours, you consume 1,000 watt-hours, which is termed a kilowatt hour. In other words, most, if not all, consumers acquire their understanding of a kWh from the concept of watts, and not the other way around. In this case, a kWh is best understood if it is viewed as the summation of watts over a period of time. Similarly, when a customer buys an electric hair dryer or an electric iron, they look at the power rating of that appliance, which is again expressed in watts. Finally, if that customer had purchased a high wattage hair dryer and a high wattage electric iron, and decided to run both at the same time, they may have tripped the circuit breaker, requiring a trip to the garage to reset after one of the two appliances had been unplugged. This is yet another way through which customers have become familiar with the concept of demand as opposed to usage.

V. Conclusions

The timing is propitious for making cost-reflective three-part rates the standard offering for all residential customers. The arrival of smart meters has made it possible to begin to offer three-part rates to residential customers. Such rates will encourage better utilization of grid capacity, minimize opaque cross-subsidies between customers, and foster adoption of new advanced technologies. Bringing demand charges to residential rates will also bring greater uniformity in rate designs across customer classes, which may reduce regulatory costs, especially if there is more agreement on the concepts applied when deciding how an electric utility should bill its customers.

Three-part rates are already being offered by several utilities around the country, and there is considerable precedent for time-varying and multiple-part rates in other industries. Membership grocery stores like Costco charge an annual fixed charge and then a volumetric charge for all items on the shelves. Analogously, the electricity utility can stabilize revenue and recover fixed costs with one rate component and recover variable costs with another. Sports franchises and concert venues commonly change ticket prices based on demand. Similarly, ride-sharing services like Uber charge various levels of “surge pricing” when demand is unusually high. Uber’s pricing may encourage more drivers to get on the road and customers to take fewer rides or consider car-sharing (i.e., Uber Pool). The analogy to the electricity industry is clear- demand charges and time-varying prices can encourage more generators to come online at peak times and discourage customers from imposing unnecessarily high demand. The criticism that customers will not accept or understand demand charges can be addressed through customer outreach and education. Also, customers are already likely familiar with concept of electricity demand from their experiences in choosing light bulbs and appliances, which are labeled and advertised according to wattage.

The transition to three-part rates may require careful planning on the part of utilities to ensure that changes are gradual, well-marketed and considerate of customer input. For example, temporary bill protection and graduated increases in new rate components can help mitigate sudden bill changes for customers. Also, rate designers must be careful to ensure that new rates do meet the objective of cost alignment and do not create new cross subsidies. If special considerations are needed for customers with medical disabilities or income constraints, the best way to deal with them is grant those customers an income subsidy and not distort the rates.

If peak demand reductions are a primary goal, rates must also be actionable so that customers can manage their demand and adopt behavioral and technological responses that will actually lower their bills.

While the transition to the three-part rate must be a thoughtful endeavor, the long-term benefit is a more efficient and equitable electrical grid.

VI. Additional References

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VII. Appendix: The Theory of Demand Charges[39]

Demand charges are commonly included in rates for commercial and industrial customers and are increasingly becoming of interest for residential customers. In this section, we discuss the theory behind demand charges, both the historical context and the reasons that they continue to be offered by utilities today.

Historical Context

The concept of a demand charge was introduced more than a century ago. Around the turn of the 20th century, some British engineers began to advocate demand charges as "the correct device to divide a utility's fixed costs among its customers."[40] John Hopkinson – whose accomplishments include twice serving as president of the Institution of Electrical Engineers – is considered to be the first proponent of an explicit price per kilowatt, which he described in "The Cost of Electric Supply" addressed to the Junior Engineering Society.[41] Since then, a tariff comprising of demand and energy charges has come to be referred to as a "Hopkinson rate."

In the commercial sector, demand charges have been implemented for nearly a century. Economic historian John Neufeld pinpoints the introduction of demand charges in the United States to sometime between 1906 and 1917. In 1906, the National Electric Light Association published a confidential report on electric rates for 1,183 American cities. While "significant information may have been lost" in the 1906 report, Neufeld notes that none of the cities in the report mentioned Hopkinson rates. In contrast, when the Rate Research Committee

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39 This section was developed by Josephine Duh.

40 John L. Neufeld, "Price Discrimination and the Adoption of the Electricity Demand Charge," *Journal of Economic History*, 1987, Vol. 47, No. 3, 693-709.

41 John Hopkinson, "The Cost of Electric Supply: Presidential Address to the Joint Engineering Society," 1892, in: Original Papers by the Late John Hopkinson, Volume 1, Technical Papers, Cambridge University Press, 1901.

published the first annual survey of electricity rates in 1917, 84.1 percent of Power and 91.8 percent of Industrial Wholesale or Primary Service had demand charges in their rates.[42]

Since the early 1900s, demand charges have intermittently surfaced in the academic literature. In particular, interest in demand charges surged during the late 1970s and early 1980s when utilities from various states conducted time-of-use pilot studies. As discussed in several theoretical papers[43], one of the great challenges to modeling electricity consumption with a demand charge is accounting for the different bases (i.e., kilowatt versus kilowatt hour). To make the problem tractable, researchers often made simplifying assumptions so that maximum demand could be written as a function of energy consumption. In the empirical experimental and non-experimental studies, the findings were mixed. Differences in methodology, small sample sizes, and inherent differences in the context of the program have been cited as reasons.[44]

In recent years, the advent of distributed generation for residential customers has rekindled the debate over demand charges in electricity rate design. As rooftop solar and net-energy metering continue to proliferate in the United States as well as Europe and Australia, stakeholders recognize the efficiency and equity issues associated with the two-part tariff structure composed of a modest fixed charge and sizeable energy charge. In an effort to help stakeholders understand the tradeoffs, the volume of literature about the options for rate design has rapidly grown.[45] This whitepaper consolidates both the points of consensus and debate from the existing literature and from our experience in the industry.

Ratemaking Objectives

Discussions about rate design commonly refer to Bonbright's ten principles for public utility rates.[46] They can be distilled to the following five ratemaking principles:

1. Economic efficiency in consumption and production
2. Equity between customers and between the utility and the customers
3. Revenue stability for the utility
4. Bill stability for the customer
5. Customer satisfaction

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42 Neufeld, 1987.

43 E.g., see Sandford V. Berg and Andreas Savvides, "The Theory of Maximum kW Demand Charges for Electricity," *Energy Economics*, October 1983, 258-266.

44 *E.g.*, see Allen K. Miedema and S. B. White, "Time-of-Use Electricity Price Effects: Summary I," *Report Prepared for the U.S. Department of Energy*, Office of Utility Systems, June 1980; Ahmad Faruqui and J. Robert Malko, "The Residential Demand for Electricity by Time-of-Use: A Survey of Twelve Experiments with Peak Load Pricing," Energy, 1983, Vol. 8, No. 10, 781-795.

45 *E.g.*, see Carl Linvill, John Shenot, and Jim Lazar, "Designing Distributed Generation Tariffs Well," *The Regulatory Assistance Project white paper*, November 2013; Devi Glick, Matt Lehrman, and Owen Smith, "Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future," *Electricity Innovation Lab - Rocky Mountain Institute white paper*, August 2014; Toby Brown and Ahmad Faruqui, "Structure of Electricity Distribution Network Tariffs: Recovery of Residual Costs," *The Brattle Group Report prepared for Australian Energy Market Commission*, August 2014.

46 James C. Bonbright, Principles of Public Utility Rates. New York: Columbia University Press, 2nd Edition, 1961.

Economic efficiency means that the available resources cannot be put to other uses without incurring a loss to society overall.[47] In other words, the net gain in societal value from a reallocation of resources for either electricity consumption or production would be zero or negative, which would be the case if at least one consumer or producer was (or were) worse off than before the reallocation. Economic efficiency is maximized when rates are designed to reflect the underlying cost structure of producing and delivering electricity.

While efficiency makes no distinction among consumers or producers and focuses on aggregate welfare, equity, the second criterion in the list above, takes distributional concerns into account. Whether the "winner" from reallocation is a low-income or high-income household is a distributional concern. Concepts of equity are rooted in theories of social justice.[48] Differences in subscribed theories can be a profound source of disagreement.

Revenue stability and bill stability are criteria that address the following question: What pricing strategies allow utilities to recover investment costs while protecting customers from unmanageable fluctuations in their bills?

The fifth criterion, customer satisfaction, affects the feasibility of implementing changes to rate structure. Regulators and utility companies would be reluctant to impose changes that would cause a backlash from customers.

The Theory of Demand Charges

Current residential rates represent a mismatch between the utility's revenues and costs. For most utilities in the United States, residential revenues are based largely on volumetric rates and therefore tied closely to energy sales. If energy consumption rises, then revenues increase; if energy consumption falls, then revenues decrease. But a large share of a utility's costs are actually driven by investment in infrastructure, such as generation capacity and transmission and distribution (T&D) networks. These costs are not directly related to the amount of energy that is consumed; they are, instead, driven by various measures of maximum electricity demand.

A "three-part tariff" would more closely align revenues with costs. The three-part tariff includes three charges: a fixed monthly charge (i.e., $/month), a variable charge (i.e., $/kWh) and a demand charge (i.e., $/kW). The three largest components of a utility's costs are generation (or energy procurement), transmission, and distribution.[49] For each of the three components, there is a fixed cost for overhead and a variable cost that is proportional to either

47 Economists know this concept of efficiency as "Pareto efficiency."

48 Broadly speaking, theories of social justice fall into one of four categories: utilitarianism, libertarianism, egalitarianism, and communitarianism.

49 For California's three largest investor owned utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric), these three components account for 90 percent of the utility's revenue requirements. In 2014, generation was 41-49 percent of the revenue requirement, transmission was 8-13 percent, and distribution was 31-36 percent. See California Public Utilities Commission, "Public Utilities Code Section 748 Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases," 2015. <<http://www.cpuc.ca.gov/NR/rdonlyres/1B413993-31EC-4235-8204-90FB6CFCB373/0/SB695ReportFINAL.pdf>>

the cumulative amount of energy consumed (kWh) or the maximum amount of energy consumed at a point in time (kW). Under the three-part tariff, the consumer pays flat fees for the fixed service costs, time-varying volumetric charges for variable generation costs, and demand charges for variable transmission and distribution costs as well as for reserve generation capacity.

The fixed cost for service would include administrative costs and overhead costs. These costs include staffing that is needed to run the power plants, maintain the network, and provide customer support. They also include the cost of metering and billing.

The variable cost for generation (or procurement) is proportional to the cumulative stock of energy consumed. For example: for a coal-fired power plant, more energy means burning more coal. Fuel, such as coal, and maintenance are examples of variable costs for generation. Moreover, the variable cost for generation is higher at peak times than off-peak times; at peak times, generators with higher marginal costs are brought on-line to meet demand. The time-varying volumetric charge for peak and off-peak times directly addresses this feature of energy supply.

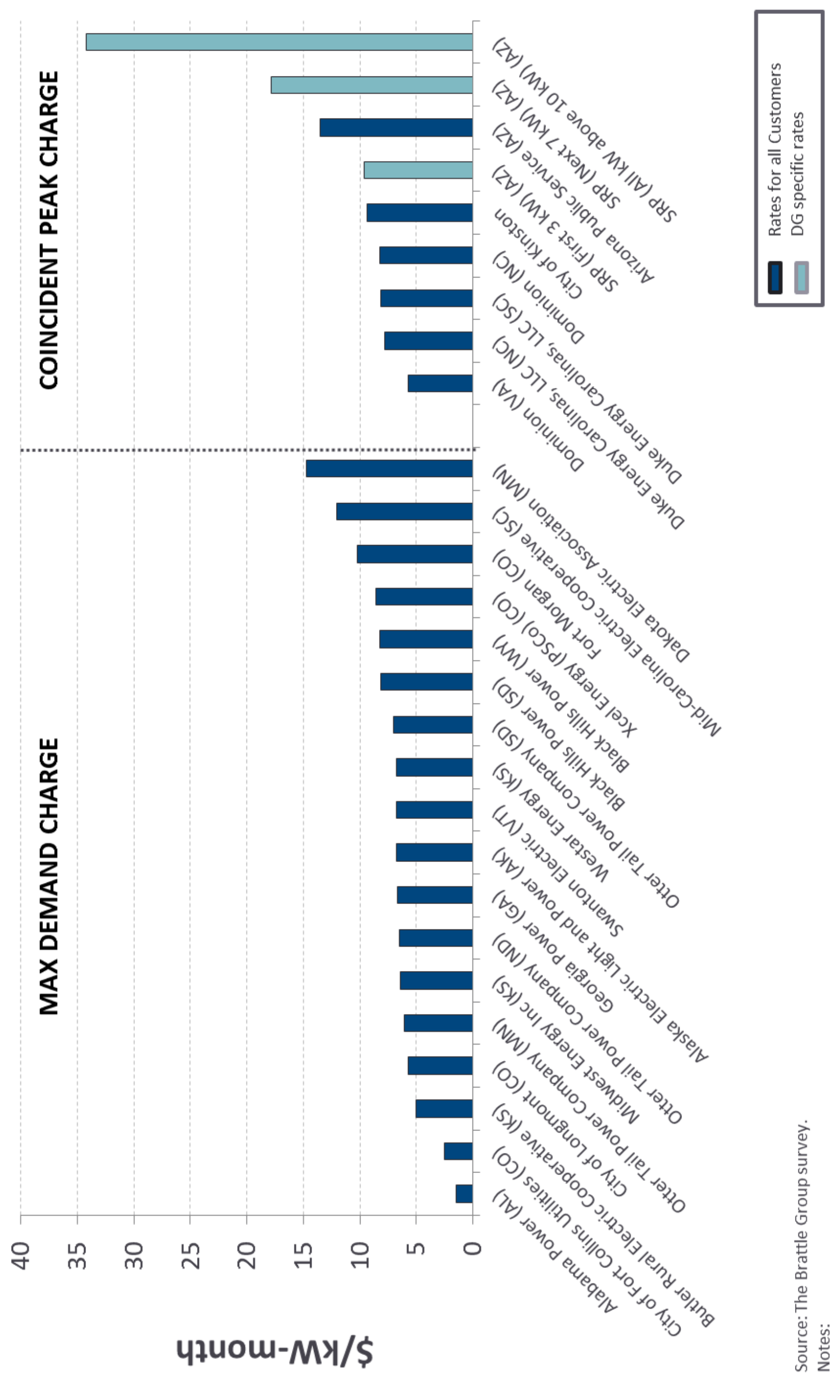
The variable cost for transmission and distribution is proportional to the maximum demand on the system at a point in time, measured in kW. Higher demand increases costs from losses caused by resistance and congestion.

The cost of reserve generation capacity also varies with maximum demand. Larger generation capacity requires more infrastructure investment. The reserve capacity is important to ensure that the supply of electricity is reliable. Inadequate reserves risk blackouts at times of high usage, which can have detrimental consequences to the economy and population. Thus, reserve margins are regulated.

The three-part tariff is designed to have the same basis as each of the key components of costs (fixed fee, kWh, and kW). By sharing the same basis, revenues track costs more closely than with the current two-part tariff structure.

A natural definition of equity is cost causation. Under the cost-causation principle, customers who drive up the costs in the system should pay proportionally higher amounts than low-cost customers. The three-part tariff fits with a definition of equity based on the cost-causation principle. But despite the theoretical support for demand charges and a long history of experience with the rate, industry stakeholders have mixed perceptions of the merits of this rate option for residential customers.

Figure 7: Summer Demand Charges in Existing Rates



Source: The Brattle Group survey.
Notes:
1) All rates apart are drawn from their respective utility tariff sheets, valid as of April 2016.
2) SRP has a tiered demand charge in which higher increments of demand are charged a higher price.