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Memorandum

From the office of
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Arizona Corporation Commission
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DATE: August 4th, 2016

FROM: Commissioner Andy Tobin's Office

SUBJECT: Docket No. # E-00000J-16-0257

Attached please find Sean Gallagher supplemental presentation entitled "Charge Without a Cause" & "Rate Design for a Distributed Grid" for the Reducing System Peak Demand Cost Workshop that was on August 4th, 2016.

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Charge Without a Cause?

Assessing Electric Utility Demand Charges on Small Consumers

Electricity Rate Design Review Paper No. 1

July 18, 2016

Paul Chernick
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Charge Without a Cause?

Assessing Electric Utility Demand Charges on Small Consumers

Electricity Rate Design Review Paper No. 1

Introduction & Overview

There has been significant recent attention to the possibility of including demand charges in the electricity rates charged to residents and small businesses. Electric utilities have historically served these 'small customers' under a two-part rate structure comprised of a fixed monthly customer charge that recovers the cost of connecting to the grid and an energy charge (or charges) that recover all other costs. Much of this attention to the issue of demand charges for small customers has been initiated by electric utilities reacting to actual or potential reductions in sales, revenue and cost recovery.

Demand charges are widely familiar to large, commercial and industrial customers, where they are used to base some portion of these customers' bills on their maximum rate of consumption. While a customer charge imposes the same monthly cost for every customer in a rate class, and an energy charge usually imposes the same cost per unit of energy used over a long period of time (e.g. the entire year, a month, or all weekday summer afternoons), most demand charges impose a cost based on usage in a very short period of time, such as 15 minutes or one hour per month. The timing of the specific single maximum demand event in a month that will result in demand charges is generally not known in advance.

The goal of this document is to unpack the key elements of demand charges and explore their effect on fairness, efficiency, customer acceptability and the certainty of utility cost recovery. As will be evident, most applications of demand charges for small customers perform poorly in all categories. Following are five key takeaways:

- Residents and small businesses are very diverse in their use of electricity across the day, month and year — most small consumers' individual peak usage does not actually occur during peak system usage overall. This means that traditional demand charges tend to overcharge the individual small consumer.
- Apartment residents are particularly disadvantaged by demand charges because a particular apartment resident's peak usage isn't actually served by the utility. Utilities only serve the combined diverse demand of multiple apartments in a building or complex rather than the individual apartment unit.
- Demand charges are complex, difficult for small consumers to understand, and not likely to be widely accepted by the small customer groups.
- Very little of utility capacity costs are associated with the demands of individual small consumers. Nearly all capacity is sized to the combined and diverse demand of the entire system, the costs of which are not captured by traditional demand charges. If consumers actually were able to respond to a demand charge by levelizing their electricity usage across broader peak periods, then utilities would incur revenue shortages without any corresponding reduction in system costs.
- Demand charges do not offer actionable price signals to small consumers without investment in demand control technologies or very challenging household routine changes. This results in effectively adding another mandatory fixed fee to residential and small consumer electric bills.

About the Authors

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The authors thank the many colleagues from organizations around the country who offered their technical, legal and policy insights and perspectives on this paper.

Legacy Demand Charges

While there are a large number of variants on the basic theme, the standard demand charge is a fee in dollars per kW times the customer's highest usage in a short (e.g. one-hour) period during the billing month. These charges are nearly universal for industrial and larger commercial customers.

This rate design is a legacy of the 19th century, when utilities imposed demand charges to differentiate between customers with fairly stable loads over the month (mostly industrial loads) from those who used lots of energy in a few hours, but much less the rest of the month. Utilities recognized that the latter customers with peaky loads were more expensive to serve per kWh, and monthly maximum demand was the only other measurement available given existing meter technology at the time.

Beyond the standard design, variants include:

- Billing demand computed as the highest load over 15 or 30 minutes, rather than an hour;
- Charges per kVA rather than per kW, thereby incorporating power factor;
- Charges that are higher in some months and/or some daily periods than in others;
- Ratchets, in which the demand charge can be set by the highest load in the preceding year or peak season, as well as the current month; and
- Hours-use or load-factor rates, where the price per kWh declines as monthly kWh/kW increases, thereby incorporating an effective demand charge within an energy charge framework. For example:

First 200 kWh/kW	$0.15
Next 200 kWh/kW	$0.12
Over 400 kWh/kW	$0.10

For a high load factor customer (e.g. over 400 kWh/kW, or 60%), this works out to a $14/kW demand charge. But, for a low load factor customer with high peak demand at some times but otherwise low usage, like a school stadium lighting system with only 20 hours/month of usage, this rate design example works out to $1/kW (20 hours x .05/kWh built into the first 200 kWh/kW).

Demand-Charge Design Elements

As noted above, the standard demand charge uses the billing demand at the time of the customer's greatest consumption, integrated over a short period such as one hour, measured monthly. Thus, the charge is based on a single hour out of the 720 hours of a 30-day month, with each customer charged for load in whichever hour their maximum demand occurs, regardless of coincidence with the peak demand of the system. Because a customer's individual peak demand can occur at any time of day and not necessarily during the hour when system costs are greatest, the standard demand charge does not generally reflect cost causation. There are three categories of design options for demand charges: the time at which demand is measured, the period over which demand is averaged, and the frequency of its measurement.

Timing of billing demand measurement

The term "peak demand" is used in many different ways in utility jargon. These peaks include the following:

- **Customer peak:** Each customer experiences a non-coincident[1] maximum demand (NCP) at some point in the month. That value is typically used in legacy demand charges. Each customer also experiences a maximum non-coincident demand for the year (i.e. the highest of 12 monthly maximum non-coincident demands). This value is used for demand charges with ratchets.[2]

- **Equipment peak:** Each piece of utility transmission and distribution equipment experiences a maximum load each month and each year. Utilities often have detailed data on the timing of loads on substations, transmission lines, and distribution feeders. They use those data for system planning, but usually not in setting rates. The capacity of equipment varies with weather; when temperatures are cooler, equipment dissipates heat better and has more capacity.

- **Class peak:** Utilities generally estimate a class peak load for each customer class (e.g. residential, small commercial, large commercial), which may occur at different hours, months and seasons. Aggregated class peaks are often used in allocating some distribution costs to classes.

- **System peak:** The entire system experiences a maximum peak in each month, one of which will be the annual maximum peak. Loads of customers or customer classes measured at the time of the maximum monthly or annual system peak are said to be coincident demands for that month or year.

- **Designated or seasonal peak:** Utilities often designate a "peak period" for one or more months, when there is a high probability that the system's highest peak demands will occur, such as 3-7 p.m. from June through September. However, these designated peak times are based on expectations and do not necessarily coincide with actual system peak. Demand charges may measure each customer's highest one-hour demand during these periods. This is sometimes incorrectly referred to as a 'coincident peak demand charge,' or a 'demand time of use rate.'

Because of their diversity in energy usage, customers' individual non-coincident maximum loads usually do not occur at the same time as the peaks on the system as a whole — or even at the same time as peaks on the local distribution system. Thus, in addition to not reflecting the customer's contribution to utility costs, billing on the customer maximum demand does not effectively encourage customers to reduce their contribution to costs, and may actually encourage customers to move load from the times of their individual maximum demands to times of high system loads and costs. Unlike attempting to capture customer coincident demands, billing parameters for customer non-coincident load is relatively easy to measure. However, these loads are difficult to control, and a single brief unusual event (e.g. simultaneous operation of multiple end uses or equipment failure) can set the billing demand for the month and year.

With modern utility metering, utilities have the option of charging for customer loads at times that more closely correspond to cost causation — times when the system (or its various parts) is experiencing its maximum demand. A range of approaches are available:

- **Actual coincident peaks**. Because many cost allocation systems assign at least a portion of generation and transmission costs to customer classes on the basis of customer class contributions to the system peak(s) — the coincident peak or "CP" method — there is some logic behind billing on the basis of the individual customer's contribution to the system peak. A significant challenge with CP billing is there is no way to know that a particular hour will be the system peak, even as it is occurring, since a higher load may occur later in the day, month, season or year. The utility could provide customers with information on current and forecast loads, and each customer could try to respond to the *possibility* of a system peak, spreading out their response across many high load hours,

[1] The term "non-coincident" means not *intentionally* coincident with, i.e. at the same time as, the system peak. Coincidence with the system peak would only be by happenstance.

[2] The sum over customers by class of maximum non-coincident annual peak demands is used by some utilities in allocating some distribution costs.

only one of which will actually be used in computing billing demand. Like Russian Roulette, it is likely to be difficult for many residential and small commercial customers to understand and respond to this type of system.

- **Designated peak hours**. Rather than computing the billing demand for the actual system peak hours, the utility could, on relatively short notice, designate particular hours as potential peak (or potentially critical) hours and compute the billing demand as the average of the customer's load in those hours. This approach is similar to the designation of critical peak periods in some time-of-use rates or peak-time rebates in some load-management programs. Provided that the potential peak hour information can be effectively communicated to all customers subject to the structure, the ability to respond should be somewhat improved over the NCP and CP approaches.
- **Forecast peak periods.** Rather than designating individual hours for computation of billing demand, a utility could designate a peak window, such as noon to 4 p.m., when the system is likely to experience a peak or other critical condition, and set the billing demand as the customer's average consumption during that window. The hours around the system peak hour also tend to experience loads close to the actual peak load and contribute to reliability risk. Shifting load from the peak hour to one hour earlier or later may create a worse situation in that new hour. Here too, customers may be better able to respond to forecast peak periods than to individual hours, even if the period is only designated the day before or a few hours before the event.
- **Standard peak-exposure periods.** In the above examples, customers may only learn about peak periods after-the-fact or just a day or hours before they are set, but utilities could set time periods farther in advance, for instance in a rate case as part of the tariff itself. Especially for small customers, establishing a fixed period in which peaks and resource insufficiency are most likely, such as July and August weekdays or even more narrowly non-holiday summer weekday periods between noon and 4 p.m., may be more acceptable and effective than declaring the demand-charge hours on short notice. This approach trades improved predictability for customers for a diminished relationship to system costs. Customer response, such as limiting their maximum energy demands during the known peak periods, would be similar to the response to time of use rates, but with the consequences of not responding potentially more dire.

Period of billing demand measurement

Measurement of the customer's billing demand can occur over a wide variety of time frames. An instantaneous or short-duration measure of billing demand is possible but would penalize customers with overlapping loads of standard behind the meter technologies. Many residential customers have limited choice or control over when they use appliances. For example, electric furnaces and water heaters can consume significant levels of electricity, with common models drawing 10.5 kW and 4.5 kW, respectively. Air conditioners draw from 2 kW for a one-ton capacity model to 9 kW for a five-ton model. In addition, common hair dryers typically draw 1 kW and often more; the average microwave or toaster oven can draw 1 kW; and an electric kettle can draw 1 kW.

It is easy to see how the typical morning routine for a family would result in an instantaneous peak demand of as much as 18 kW and demand over a one-hour period in excess of 10 kW. A billed demand of 10 kW or more would result in high and hard-to-avoid charges, in addition to a fixed monthly charge, meaning that this household would have little to no control over the bulk of its monthly bill.

While families may be able to understand how this peak demand occurs, school schedules and work schedules may allow little flexibility to do anything about it. Further, many of these devices are designed to be automatically controlled by thermostats that would be difficult to override on a short-term basis to avoid demand charges. Moreover, these overlapping appliance demands do not drive costs on the system.

This example shows the electric demand of a morning schedule, while peak system demands are often later in the day. In addition, customer diversity can spread these demands out, diluting any effect on peak system demand.

At the other extreme, the billing demand measure could be 720 hours, for a 30-day month. This billing period would capture all the loads imposed by the customer to the utility system and requires no new metering. In fact, this billing approach is in common practice today and is known as the two-part rate, which charges customers for demand during each hour of each day of the billing period (a.k.a. energy) on top of the basic flat monthly customer charge.

Within this spectrum, the most common billing demand periods in practice today for commercial and industrial customers (outside of the two-part rate) range from 15 minutes to 60 minutes.[3] Short periods of measured billing demand are more difficult for customers to manage. For example, an apartment dweller who takes a shower and dries their hair while something is in the oven can run up demand of 10 kW or more, even though the average contribution to the system peak across units in the same apartment building is typically no more than 2 or 3 kW. Longer periods of measurement, such as 60 minutes or the average demand over several hours, tend to dilute the impacts of very short-term events.

There is great diversity in maximum loads among residential consumers. As mentioned above, demand charges have historically only been applied to large commercial and industrial customers, with a multitude of loads served through a single meter, and generally a dedicated transformer or transformer bank. For very large industrial customers, there is typically a dedicated distribution circuit or even distribution substation. So for these customers, diversity occurs on the customer's side of the meter, such as when copiers, fans, compressors, and other equipment cycles on and off in a large office building.

For residential consumers, there is also diversity — but it occurs on the utility's side of the meter as customers in different homes and apartments connected to the same transformers and circuits use power at different moments in time. The point is that the type of rate design that is appropriate for industrial customers, who may have a dedicated substation or circuit, is not necessarily appropriate for residential customers who share distribution components down to and including the final line transformer.

Indeed, in the example in the previous section regarding measurement of peak demand during a window designed to capture higher-cost hours (i.e. standard peak-exposure periods), one can envision a peak demand period that covers the entire window. Such an approach may be more closely tied to cost causation, but it would be difficult for the customer to respond unless measurement occurred each day and was averaged for the full billing period.

Frequency of billing demand measurement

By far the most common frequency of measurement is once per month. However, this is not the result of careful study and analysis, but is rather a matter of convenience related to the selection of billing periods approximating one month. Months and billing periods are arbitrary creations, whereas cost variation tends to be more seasonal in nature at the macro-scale, weekly at a mid-scale (workdays vs. weekends and holidays), and daily at a micro-scale.

However, actual generation capacity requirements are driven by many high-load hours, which collectively account for most of the risk of insufficient capacity following a major generation or transmission outage,

[3] A related decision point is specifying whether the billing demand period to be measured is random or clock-based. For example, can a 60-minute billing demand period begin at any time, or should it be restricted to clock hours?

so any single peak customer load is unlikely to provide optimal price signals. Pragmatically, loads of very short duration — the highest 50 hours per year or so — are best served with demand response measures that require no investment whatsoever in generation, transmission, or distribution capacity.

Some commercial and industrial customers are subject to what are called "demand ratchets" which set the minimum billing demand for each month based on a percentage (typically 50% to 100%) of the maximum billing demand for any month in the previous peak season (summer or winter) or previous 11 or 12 months. While ratchets smooth revenue recovery for the utility, they are the antithesis of cost causation in a utility system with diversified loads, and can severely penalize seasonal loads. The resulting unavoidable fixed charges impair the energy conservation price signal to customers. Therefore, billing demands could reflect cost causation more closely by having seasonal elements, and also weekly and daily elements, but this increases the complexity. Alternatively, demands could be measured and averaged over the 100 hours each month that contribute most to system peak loads.[4]

Finally, as discussed relative to the period of measurement, if kW of demand were to be measured in every hour of the month and summed, the result would be the current two part rate with no additional more expensive metering required.

Evaluation of Demand Charges

Loads, load management and load diversity

The costs that utilities typically recover in existing demand charges applied to large customers include those that are usually assigned to customer classes on the basis of a demand allocator.[5] These costs tend to be fixed for a period of more than one year, and usually include one or more of the following:

- Generation capacity costs (cost of peaking generators and all or a portion of the cost of baseload[6] units)
- Transmission costs (all or a portion)
- Distribution costs (all or a portion of distribution circuits and transformer costs)

Some utilities utilize separate demand charges for each major function, or sometimes group functions together, such as generation and transmission, that are allocated to customer classes on similar bases.

Because billing demand is a function of the total load of a customer's on-site electrical equipment operating simultaneously for a relatively short period of time, the demand charge may act as an incentive to levelize demand across the day. The types of large commercial and industrial customers that are currently subject to demand charges are usually sophisticated enough to understand the sources and timing of their electrical equipment and its consequent energy consumption.[7] Many, i.e. over half,[8] have

[4] Such a system would be more likely to capture high loads and peak demands on the system sub-functions, e.g. transformers, feeders, substations, transmission, and generation.

[5] It should be noted that some jurisdictions allocate a portion of fixed costs on average demand, or energy.

[6] Because baseload units serve all hours, many regulators have used the Peak Credit or Equivalent Peaker method to classify baseload plant costs between Demand and Energy. For example, in Washington, it's about 25% demand, 75% energy. In marginal cost studies, only the cost of a peaker is typically considered demand-related.

[7] Most utilities do not apply demand charges to small commercial customers under 20-50 kW demand.

energy managers whose job in part is to manage that energy consumption in light of the rates and rate structure of their local utility. Monitoring and load management equipment can be employed to maximize profitable industrial processes while avoiding new, higher peak demand charges. In other words, sophisticated large commercial and industrial customers may use energy management systems to restrain demand by scheduling or controlling when different pieces of equipment are used like fans, compressors, electrolytic processes, and other major equipment, in order to levelize the load over the day. Because these large customers have a diversity of uses on their premises, they may be able to manage that diversity to present a relatively stable load to the utility.[9] However, because individual customer demand often does not coincide with system demand, much of the demand management activity by the more sophisticated large customers is essentially pointless and wasteful from a system cost perspective.

Moreover, while it appears utilities believe demand-charge revenues are more stable than energy revenues, the stability of demand charge revenue even for large customers is highly dependent on the size, load factor and weather sensitivity of the large customers.

The sophistication of large customer energy management does not currently exist for most small commercial and residential customers. These customers have a great deal of load diversity, but that diversity is not within a single customer but between different customers using power at different times (see Appendix B). In these classes, because each customer is served through a separate meter, it is unlikely that individual constituents will have much ability to reduce the overall system demand or their own maximum billing demand in any significant way without acquisition and effective use of advanced load monitoring and management technologies. Residential demand controllers are marketed to all-electric customers (e.g. at some rural utilities with limited circuit capacity) that have implemented demand charges. These do enable customers with electric cooking, water heating, clothes dryers, space conditioning, and swimming pools to levelize their demand. But for urban apartment dwellers and other low-usage customers, the natural diversity between customers is much greater than the potential control over the diversity of uses within a household.

Technologies to manage and control this diversity of small customer usage are best deployed as demand response measures, targeted at hours that are key to the system, not to the individual consumer usage pattern. As a result of the small customers' lack of ability to control individual peak demands, a demand charge on small customers acts effectively as a fixed charge and generally provides a more stable and consistent revenue collection vehicle for the utility than volumetric energy charges.

Cost drivers and load alignment

Evidence shows that small residential customers are less likely to have their individual high usage occur at the time of the system peak demand, whereas large residential users are more likely. This is simply because large residential users are more likely to have significant air conditioning and other peak-oriented loads. Large residential users' loads tend to be more coincident with system peak periods and thus more expensive to serve. As a result of these load patterns, on an individual customer basis large residential users have higher individual load factors, meaning they will pay lower average rates if a non-coincident demand charge is imposed.

The figure below shows this relationship, in the context of residential customers:

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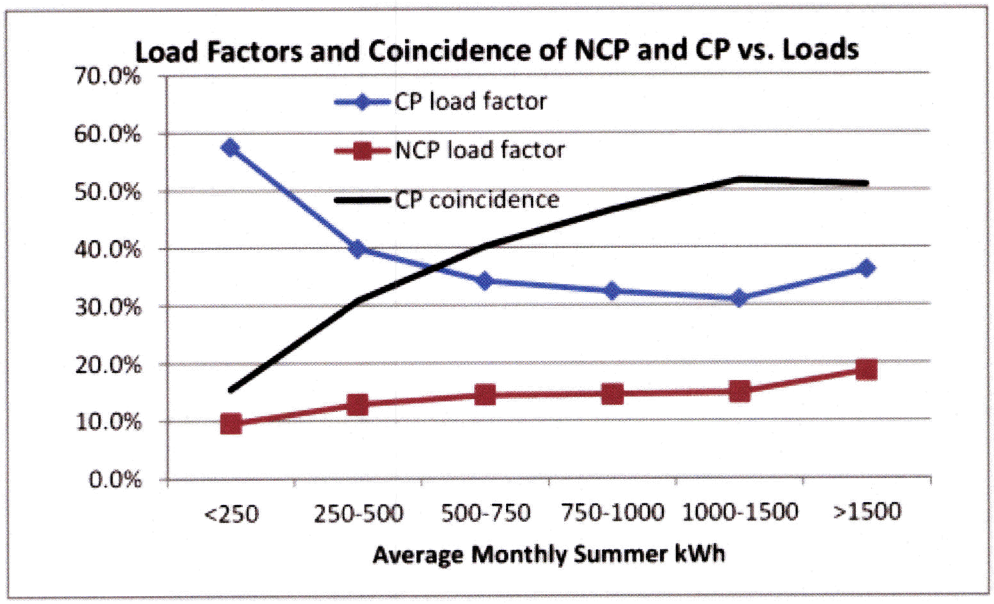
[8] A Review Of Alternative Rate Designs Industry Experience With Time-Based And Demand Charge Rates For Mass-Market Customers; Rocky Mountain Institute, p. 76, May 2016 download at: www.rmi.org/alternative_rate_designs

[9] That stable load may not be less expensive to serve than the customer's most efficient load.

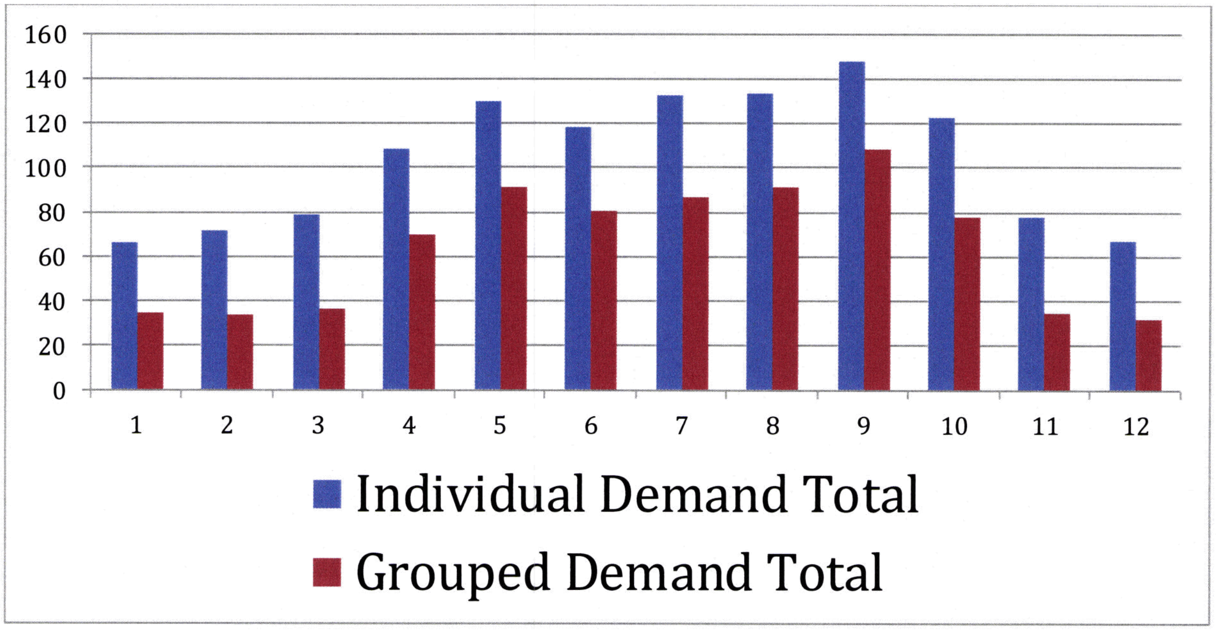


Source: Marcus Presentation to WCPSC, June 2015

The black line shows customers whose individual peak demand coincides with system peak tend to have both higher monthly energy use (kWh) and higher metered individual load factors. The red line shows that larger-use customers have higher individual metered non-coincident load factors. The blue line shows that smaller-use customers have higher "group" collective load factors, measured relative to the system coincident peak.

As described above, the breadth of equipment on a large commercial or industrial customer's site results in load diversity behind the meter allowing for a fairly smooth load pattern for these larger customers. Smaller customers without the same degree of behind the meter load diversity have many small appliances that often operate for short periods of time. It takes but a few operating simultaneously to establish a peak demand. For a large group of 100,000 to one million customers or so, there is a general pattern for the class load and in many cases it tends to drive the utility's peak demand towards later in the day, but on an individual customer basis, peak loads can occur at any time during the month depending on the lifestyle, ages of family members, work situation, and other factors.

Apartments are particularly affected. About three-quarters of apartments in the US have electric water heaters. An electric water heater draws 4.4 kW when charging, but only operates about two hours per day, for a total of about 9 kWh of consumption per day. But each apartment has its own water-heating unit. Combined with hair dryer, range, clothes dryer, and other appliances, an apartment unit may draw 10-15 kW for short periods, but only about 0.5 to 1.0 kW on average (360-720 kWh per apartment per month). Because many apartments are served through a single transformer and meter bank, what actually matters to system design is not the individual demands of apartments, but the combined (diverse) demand of the building or complex. The illustration below shows how the sum of individual apartments' maximum hourly demands in one apartment building (in the Los Angeles area) compares to the combined maximum hourly demand for the complex:



Source: RAP Demand Charge Webinar, December 2015

The equity of rates and bills for apartment residents, where each household has few residents, but the entire building is connected to the utility through a single transformer bank, must also be addressed because the utility does not actually serve the consumption of individual customers, but only their collective needs. Finally, if customers do respond and levelize their consumption across the day or across the peak hours to minimize their demand charges, then the rates designed will not produce the revenue expected but any impacts on system costs (e.g. avoided upgrades or expansions) would likely not occur for years.

Appendix B contains residential load curves for customers in New Mexico and Colorado covering the four summer peak days for the utility providing service. It is clear from these charts that individual residential customer load is volatile, and not subject to consistent patterns that the customer would be in a position to manage. Each customer experienced its individual peak at a unique time. The collective group peak was not at the time of each individual customer's peak in any of the months. The bottom line is no discernible cost causation relationship with individual customers' peak demand.

Metering costs and allocation

Finally, demand charges also require more complex, and expensive, metering technologies than conventional two-part tariffs. The cost-effectiveness of these upgrades should be analyzed on their own merits, and where the costs are justified by energy savings or peak load reduction, they should be treated in the same fashion as the costs that are avoided, with only the portion justified by customer-related benefits (e.g. reduced meter reading expense) treated as customer-related. The remainder would be attributed to such drivers as energy costs and coincident peaks. For more information, see Smart Rate Design for a Smart Future for a discussion of how Smart Grid costs should be classified and allocated in the rate design process.[10]

[10] Regulatory Assistance Project, Smart Rate Design for a Smart Future, 2015.

Demand charges as a price signal

Imposition of demand charges runs counter to the ratemaking principles of simplicity, understandability, public acceptability, and feasibility of application. It's a formidable task to try to train millions of customers in the meaning of billing demand, the factors driving it, and how to control and manage it. Indeed, RMI (2016, p. 76) notes "[w]hile it's possible that, if customers are sufficiently educated about a demand charge rate, they will reduce peak demand in response, no reliable studies have evaluated the potential for peak reduction as a result of demand charges." The same RMI report indicates that time-varying energy charges are more effective at reducing peak demands than are demand charges.[11] Additionally, the Brattle Group reported a peak load reduction of less than **2%** for residential demand charges, compared with reductions as great as **40%** for critical peak pricing energy rates.[12]

The examples given in Appendix B show no pattern that a customer might be able to manage in advance — which is the knowledge required in order to control a peak demand occurrence. In part this is due to a mix of appliances that are set to turn on and off automatically as needed (e.g. air conditioning, hot water heaters, refrigerator) and others that are under the control of the home or small business owner (e.g. lighting, hair dryers, kitchen appliances, television). Without sophisticated load control and automation devices, it is unclear how small customers could manage peak loads. Without installation of such load control technology, a demand charge is not an effective price signal. Importantly, a charge like a demand charge is only a price signal if the customer can respond to it. If not, it becomes an unmanageable fixed charge with a substantially random character.

Indeed, large residential customers with many appliances (e.g. swimming pool heaters and pumps) that have higher load factors may benefit from demand charges as cost recovery is shifted to a charge based on a single peak demand from demand-related costs being applied against every kWh. This has been true with the larger commercial and industrial class as well. Conversely, low usage customers — including low-income customers — would likely pay more on average.

The Bonbright Criteria

Professor Bonbright's famous 1961 work, Principles of Public Utility Rates, outlined eight criteria of a sound rate structure. It is useful to consider how demand charges fare under these criteria and the following summary addresses each criteria.

1. **The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.**

   Simplicity: While the demand rate itself can be viewed as simple — a single charge applied to a single parameter — the concept of demand integrated over a short time frame (e.g. 15 minutes or one hour) is not simple and requires customer education.

   Understandability: The application and management of demand rates is likely to be difficult because customers cannot easily manage the demand in the short time intervals typically applied to demand charge rate design.

[11] A Review Of Alternative Rate Designs Industry Experience With Time-Based And Demand Charge Rates For Mass-Market Customers; Rocky Mountain Institute, May 2016 download at: www.rmi.org/alternative_rate_designs

[12] Presentations of Ahmad Faruqui and Ryan Hledik, EUCI Residential Demand Charge Summit, 2015.

Public acceptability: Demand charges are not likely to be readily accepted by small customers for the reasons outlined above. Indeed, for most consumers they will just seem like another fixed charge. (See Arizona Public Service Company case study below.)

Feasibility of application: While technically feasible, new metering is required. The likely metering technology is smart meters that can also be used for more appropriate time-varying rates (although some claim the smart meter only estimates the peak demand). As noted above, it is not clear that customers can respond to demand charges; for many utilities, the attraction of demand charges for small customers may be that customers will not be able to avoid them.

2. **Freedom from controversies as to proper interpretation.**

Proper interpretation of demand charges will be difficult for customers who don't have the behavioral or technological ability to understand, prepare for and manage peak demands in advance. This may result in misunderstandings, frustration and increasing complaints. A utility should be able to demonstrate that the smallest customers currently on demand rates understand their bills, before applying demand charges to still smaller customers.

3. **Effectiveness in yielding total revenue requirements under the fair-return standard.**

Rate structures that establish an effective relationship between billing parameters and cost causation are reasonably likely to yield total revenue requirements following implementation. However, it is clear that individual maximum demands for small customers are very diverse and rarely occur at the time of maximum system demand. To the extent small customers are able to respond to the demand price signal, they may move their peak load from a less costly time of day to a more costly time of day, and their measured demand (and the associated revenue) may vary sharply from month to month as different appliances happen to be used simultaneously generating the measured demand upon which the charge is based. Thus the link with cost causation is weak, and achieving total revenue requirements is more at risk.

4. **Revenue stability from year to year.**

Similarly, the weak cost causation link can cause instability as a significant portion (often 60% or more) of a small customer's revenue is dependent on the relative stability of a single 15 minute or one hour period during the entire month. Customer peak demand, particularly for air conditioning customers, is highly temperature sensitive, so mild summers may result in severe undercollection of revenues.

5. **Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")**

Here, too, it is unclear whether demand charges for small customers will be stable over time, but given the volatility of small customer loads, bills may lack stability. If small customers are unable to respond to the demand charge price signal, then the demand charge will act as a fixed charge and the *rate* would likely be stable. If over time small customers are able to use technologies or behavioral changes to reduce maximum demands, utility revenue may drop significantly and the rate will need to be increased to recover allowed revenues, and thus will be less stable. This paradoxical situation results in the shifting of costs from those able to manage peak loads to those who are unable.

6. **Fairness of the specific rates in the apportionment of total costs of service among the different customers.**

As pointed out above in comparing customers of different sizes (see for example the apartment dwellers discussion), small customers tend to have lower individual load factors, i.e. higher peak demands relative to their energy consumption, but higher collective group load factors (which drive utility capacity needs). In fact, lower use customers tend to have less coincidence of their individual peak demands with the system peak demand. As a result, demand charges paid by these customers would be associated with a time period that is not correlated with cost causation. This would place an unfair burden on small customers.

7. **Avoidance of "undue discrimination" in rate relationships.**

   As above, the lower coincidence of individual peak demands of lower use customers with system peak loads should lead to lower charges or bills, but applying the same demand charges to the customer's peak demand whenever it occurs would generate high charges and bills, thus discriminating against low use customers.

8. **Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:**

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service (on peak versus off peak electricity, Pullman travel versus coach travel, single party telephone service versus service from a multi party line, etc.).

As noted in the body of this paper, in addition to a lack of coincidence with cost-causing system peak loads, demand charges (particularly NCP demand charges) are generally not actionable for small customers. Thus the small customer cannot respond to this "signal" in any meaningful way that might result in lower utility costs.

More importantly, there is evidence that small customers can and do respond to price signals based on energy charges that vary by time or usage. Shifting cost recovery from energy charges to demand charges reduces the customer's incentive to reduce consumption, and results in an inefficient use of resources.

Finally, the authors of this paper support the concept of **customer agency.** In other words, the customer should have choice, control, and the right of energy self-determination. Demand charges without associated technology to control demand tend to act as fixed and unavoidable charges, and will have the effect of reducing the variable energy rate. These rate changes can significantly diminish the incentive for customers to reduce energy consumption through behavioral changes, energy efficiency technologies, or distributed generation resources and result in increased fossil fuel emissions.

Arizona Case Study

While no regulatory Commission has approved mandatory demand charges for residential customers in recent memory, this has not always been the case. A real world example is Arizona Public Service Company's (APS) residential demand rate. APS has an optional demand charge residential rate, which has been in effect since the 1980s and currently has about 10% enrollment. The customers who self-select onto this rate design are those whose usage patterns benefit from this rate option; others choose a TOU rate or an inclining block rate. The Company assists customers in identifying the lowest cost rate option for their individual usage patterns.

In a 2015 case study performed by APS, the utility explains that its optional residential demand rate "helps customers select the best rate at time of new service through [its] website rate comparison tool."[13] An examination of the relative size of residential customers that have self-selected onto the demand rate reveals that they have an average monthly consumption nearly three times the average monthly consumption of customers on the default rate.[14]

There is important history here. In the late 1980's, as the Palo Verde nuclear plants came into service and APS rates increased sharply, the ACC implemented inclining block default rates. The company opposed this at the time, but found a work-around for large-use customers, the demand and TOU rates. The demand and TOU rates have no inclining blocks (there are no barriers to implementing both together, but Arizona has not done so), so it is a way for large-use customers to avoid the higher per-unit price for higher unit that the Arizona Corporation Commission (ACC) created in with the inclining block rate design. The Company markets the demand rate only to large-use customers who they think will benefit. Many of these customers have diverse loads behind the meter, and can benefit from a demand charge if they have (or can shape) load to take advantage of the rate design, and evade the inclining block rate. Some install demand controllers to ensure their water heaters or swimming pool pumps turn off when the air conditioning turns on.[15] So it is a self-selected subclass of customers with above-average usage, and above-average diversity. Results from this subset should not be presumed to reflect behavior or experience of other subclasses.

Use of the rate comparison tool for self-selection infers that those APS residential customers who have chosen to take service on the demand rate did so because it would lower their bills without any modification in consumption patterns. Current enrollment in APS's optional demand rate does not imply that customers in APS's territory have the ability to respond to the price signal set by demand charges. Indeed, since the customer has no way of knowing when they have hit their peak demand, it is unclear if there is even a price signal being sent. To the contrary, the fact that APS has marketed its optional demand charge rates for upwards of three decades with only 10% current enrollment demonstrates that 90% of APS's customers have either not gained an understanding of how the demand charge rate would impact them, or they have decided that the demand charge rate is not the best option for them.

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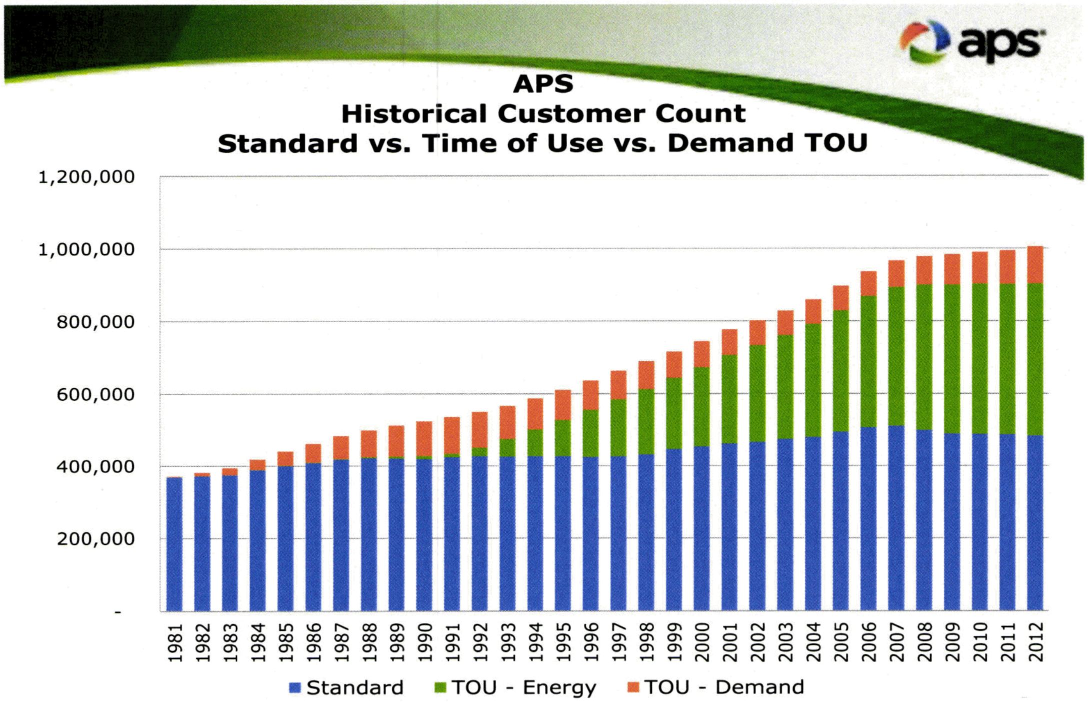
[13] Meghan Grabel, APS, *Residential Demand Rates: APS Case Study* 3 (June 25, 2015), *available at* http://www.ksg.harvard.edu/hepg/Papers/2015/June%202015/Grabel%20Panel%201.pdf.

[14] *Id.* at 7.

[15] See, for example, http://www.apsloadcontroller.com/ or www.energysentry.com for examples of devices that cost



In a recent rate proceeding, APS revealed that as many as 40% of its customers that recently switched from a two part rate to the optional demand charge rate actually increased their maximum on-peak demand. This means that even among the customers that self-selected onto the demand charge rate (mostly to save money relative to the inclining block standard rate), 40% did not respond to the demand charge price signal in their optional tariff.

It should be noted that APS's current <u>optional</u> residential demand charge tariff was originally approved by the ACC in October 1980 as a mandatory tariff for new residential customers with refrigerated air-conditioning. However, the Commission removed the mandatory requirement less than three years later, noting the change was "in response to complaints that the mandatory nature of the EC-l rate produced unfair results for low volume users." In addition, the Commission stated that removal of the mandatory demand charge would "alleviate the necessity for investment by low consumption customers in load control devices to mitigate what would otherwise be significant rate impacts under the EC-l rate."

Appendix A: Additional References

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https://www.researchgate.net/journal/1545-7907_Natural_Gas_Electricity

North Carolina Clean Energy Technology Center
Rethinking Standby and Fixed Cost Charges: Regulatory and Rate Design Pathways to Deeper Solar Cost Reductions, August 2014: https://nccleantech.ncsu.edu/wp-content/uploads/Rethinking-Standby-and-Fixed-Cost-Charges_V2.pdf

Regulatory Assistance Project
- Smart Rate Design for a Smart Future: https://www.raponline.org/document/download/id/7680
- Designing DG Tariffs Well: http://www.raponline.org/document/download/id/6898
- Use Great Caution in the Design of Residential Demand Charges: http://www.raponline.org/document/download/id/7844
- *Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs:* *http://www.raponline.org/document/download/id/7361*
- *Time-Varying and Dynamic Rate Design:* *http://www.raponline.org/document/download/id/5131*

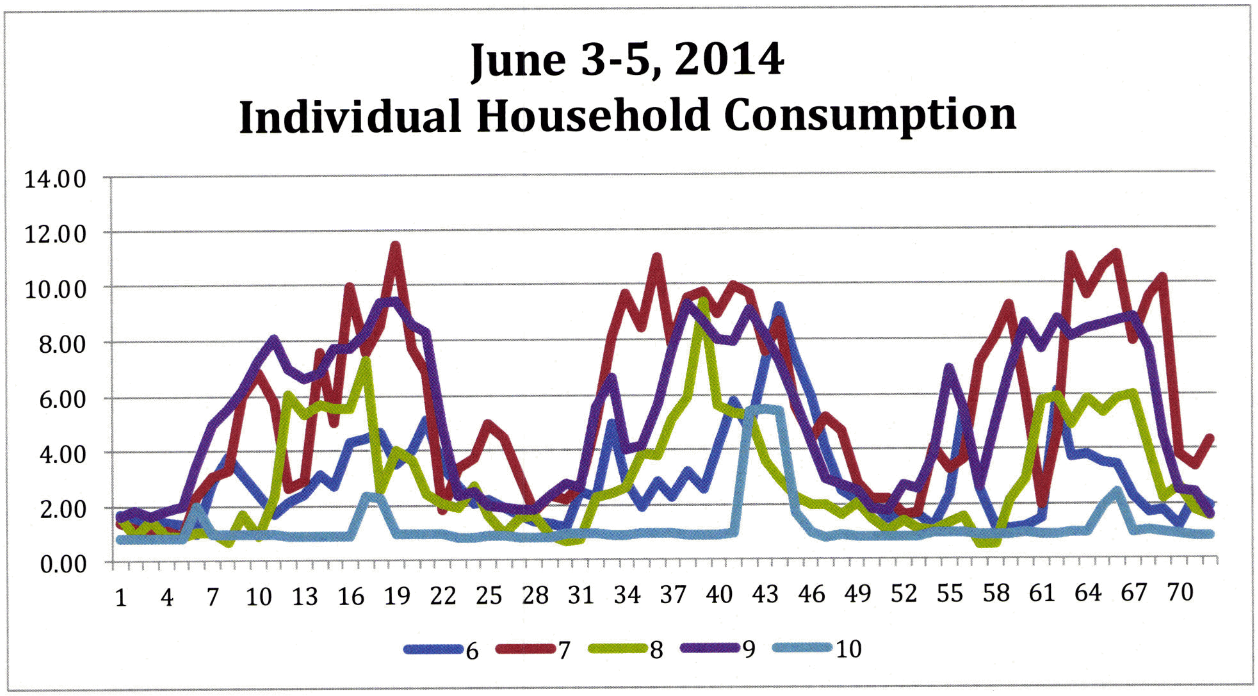
Rocky Mountain Institute
- A Review of Rate Design Alternatives: http://www.rmi.org/alternative_rate_designs

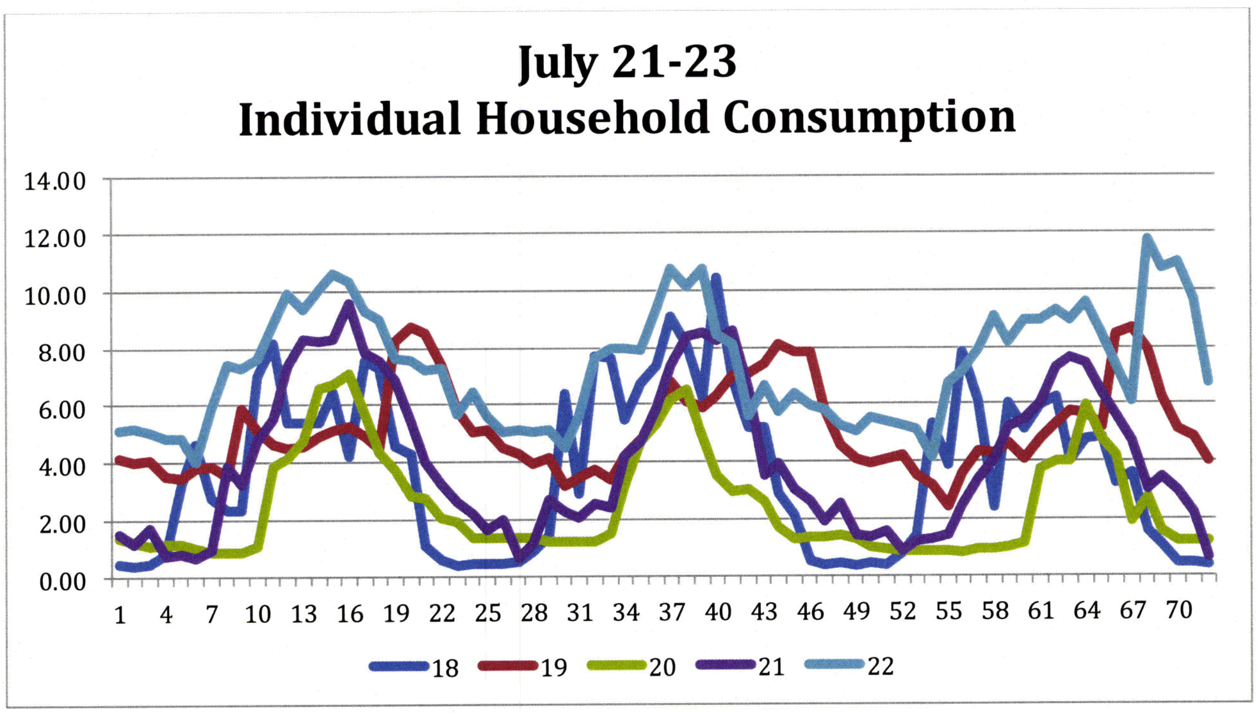
Appendix B: Sample Individual Residential Customer Loads

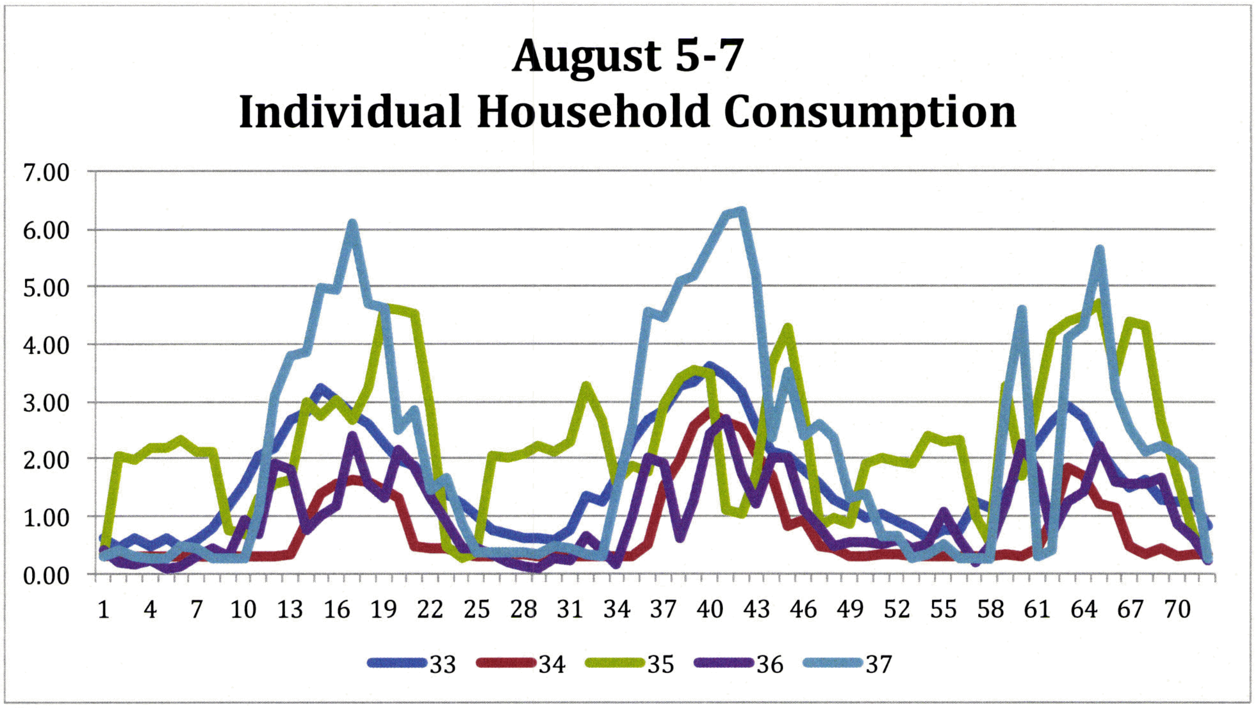
New Mexico

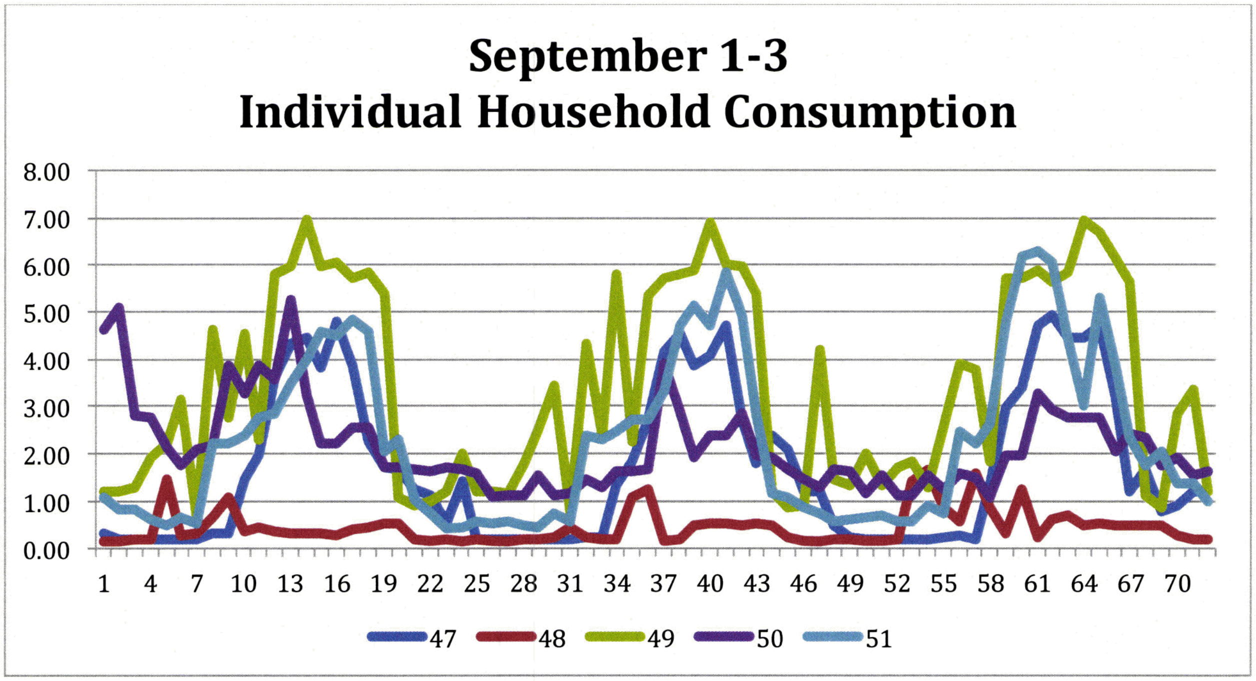
Four summer peak periods; three days and five customers per chart

(middle day is system peak day)





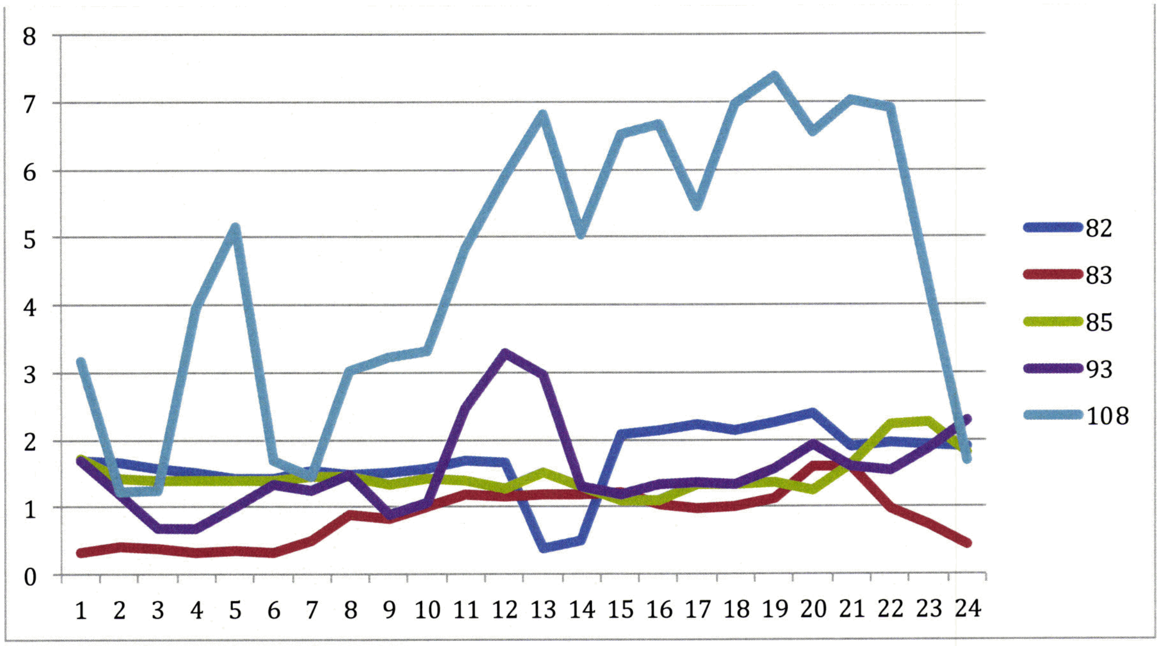

August 5-7
Individual Household Consumption
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1 4 7 10 13 16 19 22 25 28 31 34 37 40 43 46 49 52 55 58 61 64 67 70
33 34 35 36 37


September 1-3
Individual Household Consumption
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1 4 7 10 13 16 19 22 25 28 31 34 37 40 43 46 49 52 55 58 61 64 67 70
47 48 49 50 51

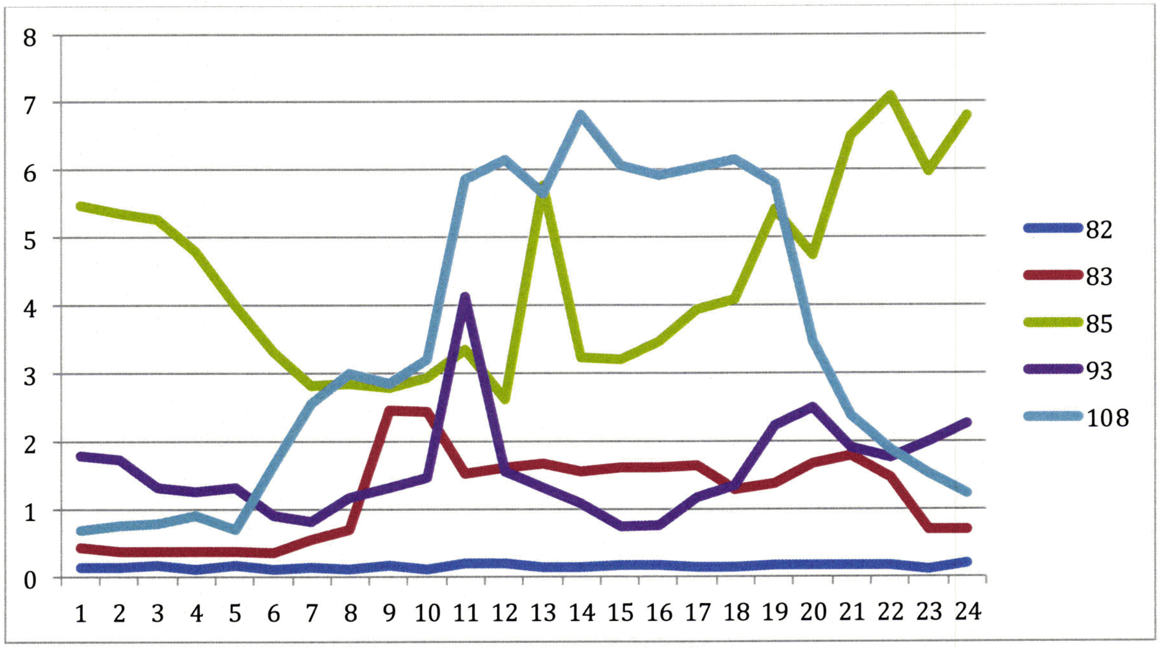
Colorado

Four summer peak days; five customers per chart

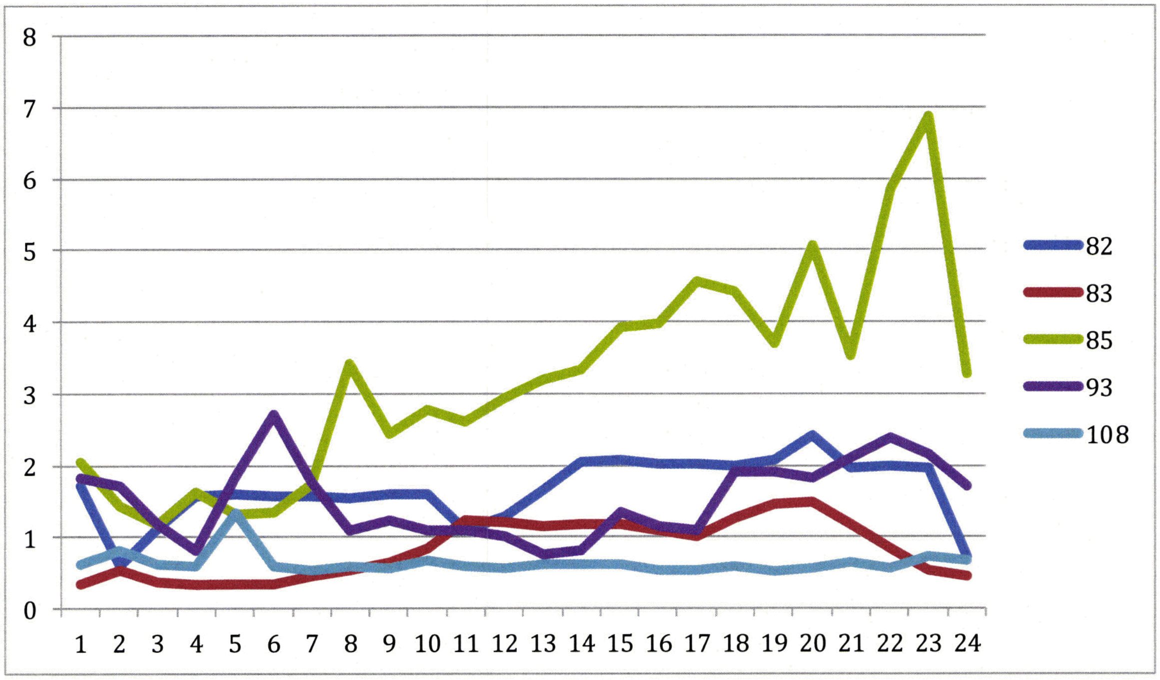
June 27, 2013



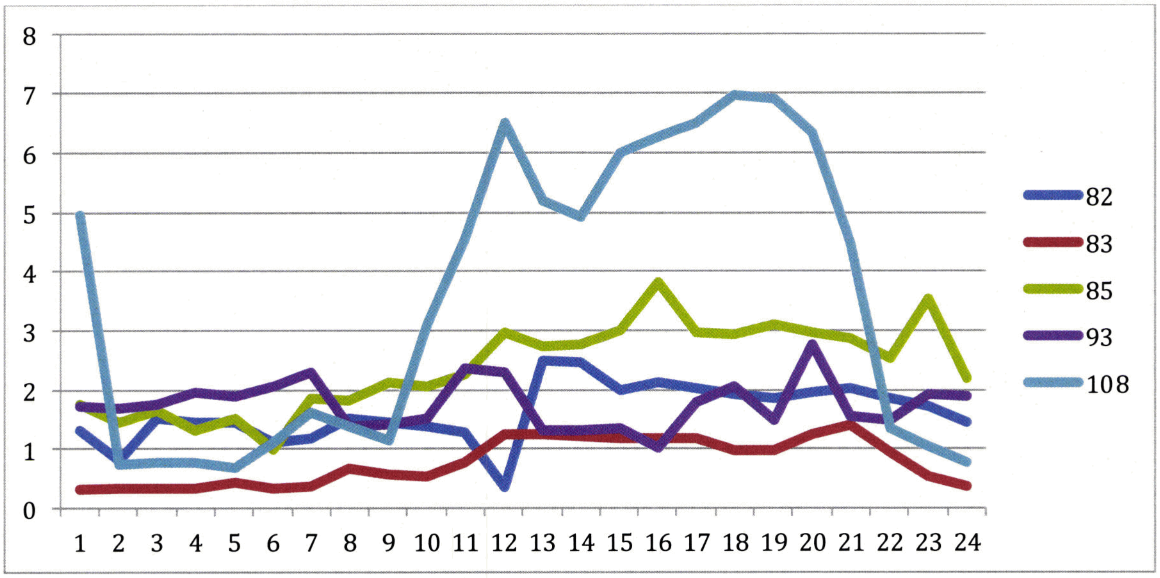
July 11, 2013



August 20, 2013



September 6, 2013



Rate Design for a Distributed Grid

Recommendations for Electric Rate Design in the Era of Distributed Generation

TechNet, Sierra Club, SEIA, Vote Solar, The Alliance for Solar Choice, CalSEIA, SolarCity

July 21, 2016

1. Executive Summary

In response to the growing popularity of rooftop solar and other distributed energy resources (DERs),[1] some electric utilities have recently begun seeking ratemaking changes that would discourage customers from generating their own power and otherwise buying less electricity from their utility. These changes – which include higher fixed charges and reduced compensation for exported energy – are justified by a purported concern about costs being shifted among customers of the same rate class.

The utilities' ratemaking ideas are often expressed by the Edison Electric Institute (EEI), most recently in a rate design "Primer" sent to the National Association of Regulatory Utility Commissions (NARUC).[2] In that document, EEI makes three fundamentally incorrect assumptions about rate design: (1) that a very large proportion of a utility's costs should be considered "fixed" costs; (2) that distributed generation and conservation do not substantially reduce those "fixed" costs or provide other benefits beyond avoiding the short-run energy cost; and (3) that rates based on volumetric energy usage and net metering invariably cause costs to be shifted from low-usage customers and those who self-generate to high-usage ones.

This paper responds to EEI first by examining the allegation that rooftop solar shifts costs onto other utility customers. We point out that the assumption of a cross-subsidy rests largely on the premise that self-generation provides no benefit to the utility and its ratepayers other than reducing the short-run cost to buy or generate power. To the contrary, we show that rooftop solar provides a wide range of benefits, including avoided generation, transmission and distribution capacity, lower wholesale market prices, reduced volatility, and avoided pollution.

In fact, when the full range of avoided costs and other benefits is considered in a complete cost-benefit analysis, solar net energy metering (NEM) – which provides retail credit for solar energy exported to the grid – has been shown to convey net benefits to non-participating ratepayers. A recent meta-analysis of net metering cost-benefit studies by the Brookings Institution concluded that "net metering is more often than not a net benefit to the grid and all ratepayers."

Next, we offer some rate design principles aimed at achieving broad ratepayer and societal benefits. Good rate design empowers customers to control their energy costs through conservation and adoption of emerging technologies while sending price signals that efficiently allocate capital investment, which can lower costs for all ratepayers. Rates should not be designed simply to protect utilities from competition, and customers are entitled to universal service, usage-based pricing, and fair compensation for energy exports.

Finally, we offer a series of reforms that that could better integrate DERs into the electric grid and maximize their value to ratepayers. In particular, DERs should be included in long-term resource

[1] "Distributed Energy Resources" include rooftop solar, energy efficiency, demand response, smart inverters, battery storage, controllable electric loads and other energy resources located behind the customer meter.
[2] "Primer on Rate Design for Residential Distributed Generation," Edison Electric Institute, February 14, 2016. http://www.puc.state.pa.us/pcdocs/1423623.pdf

planning so that utilities are not building new infrastructure, such as power plants and transmission lines that could be replaced by DERs at lower cost. In tandem with incorporating DERs into utility planning, regulators should consider changes to the utility business model – including revenue decoupling and new ratemaking mechanisms – that would mitigate the utility's financial incentive to choose rate-based capital expenses over customer-owned resources as a means to satisfy infrastructure needs.

We conclude this paper by offering the following recommendations:

- **Study the impact** of distributed resources by conducting a rigorous analysis of the costs and benefits
- **Design electricity rates that empower customers** to control energy costs and adopt new technologies that provide system benefits
- **Implement technology standards** to gradually increase the functionality and benefits of distributed resources
- **Incorporate distributed resources into utility planning** in order to defer or replace traditional infrastructure
- **Update utility business models** so that utilities have greater financial incentive to rely upon customer-sited distributed resources to meet infrastructure needs
- **Implement rate changes gradually** and incrementally, with grandfathering for customers who made long-term capital investments on the basis of previously existing rates

2. Behind the Premise of Cost-Shifting

2.1. EEI Largely Ignores the Avoided Costs Resulting from DER Deployment

EEI's arguments about rate design rest on the false premise that solar NEM customers "shift costs" onto non-NEM customers because NEM causes the utility to lose revenue in excess of the cost savings resulting from rooftop solar. This construct overlooks the numerous ways in which solar and other distributed resources make the electric system less expensive in the long run.

For example, while EEI asserts that as much as 70% of a utility's costs should be considered "fixed,"[3] utilities often define "fixed costs" very loosely, including shareholder return, income taxes, labor, transmission and distribution costs, and sometimes even some generation-related costs.[4] Viewed over the proper timespan, many of these infrastructure costs should be considered variable costs – and indeed are among the kinds of costs that investment in DERs can avoid.

Thus, EEI mistakenly assumes that reducing energy consumption though conservation or self-generation saves utilities only the short-run wholesale "energy" portion of their costs, and not the capacity or fixed infrastructure costs. Such a viewpoint presents an incomplete picture by focusing solely on short-run avoided energy cost and ignoring long-run avoided costs.

Contrary to the opinions presented in the EEI memo, in the long run, DERs can avoid a wide range of fixed infrastructure costs, including generation capacity, distribution capacity and transmission capacity while improving power quality and reliability. Although utilities have a financial interest in having regulators believe that these infrastructure costs are "fixed" – since their profits are tied to those investments – there is no doubt that many infrastructure costs are indeed avoidable over the long term through distributed solar and other DER investments.

First, by reducing peak demand, rooftop solar and other DERs reduce expensive energy and capacity needs. While it is possible to reach a point where additional solar no longer affects peak demand – if that demand shifts to post-solar hours – the experience in Hawaii at least through 2014 was that solar and efficiency reduced peak demands, as shown in Figure 1.[5]

[3] See EEI Primer on Rate Design, http://www.puc.state.pa.us/pcdocs/1423623.pdf

[4] See Lazar et al, Smart Rate Design for a Smart Future, http://www.raponline.org/document/download/id/7680.

[5] Hawaiian Electric Power Supply Improvement Plan, 2014.

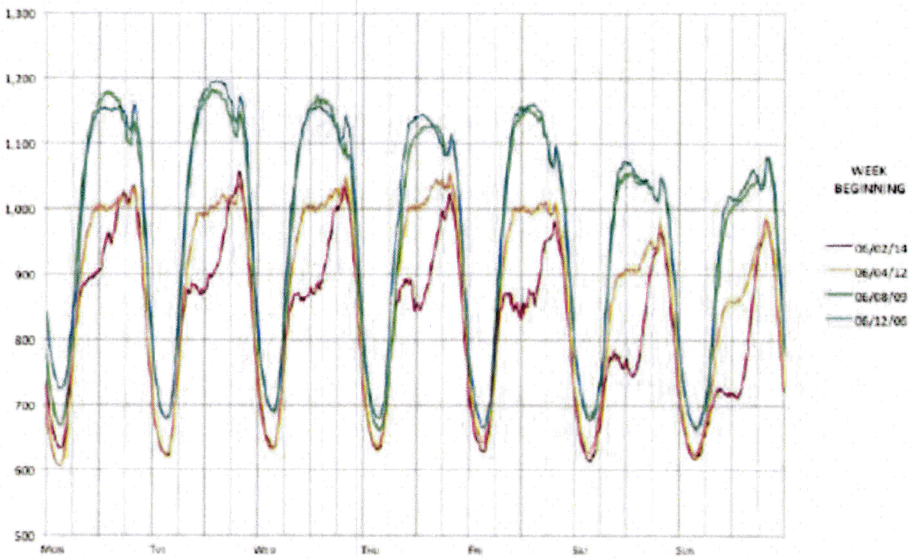


Figure 1: Oahu System Load Profiles, 2006 - 2014

In addition, distributed resources like rooftop solar reduce the need for transmission capacity – in spite of arguments made by utilities to the contrary. For instance, in its most recent transmission plan at the California Independent System Operator (CAISO), Pacific Gas and Electric Company (PG&E) recently cancelled nearly $200 million of planned transmission investments due to lower-than-expected load growth resulting from rooftop solar and energy efficiency.[6] Despite crediting rooftop solar with avoiding the need to make these major transmission investments in statements to CAISO, PG&E claimed that rooftop solar has zero potential to avoid transmission costs in separate filings related to net metering at the California Public Utilities Commission (CPUC).[7]

Beyond reducing peak demand and avoiding costly transmission investments, rooftop solar and other DERs provide direct financial benefits to utility ratepayers in other ways that are not captured by the EEI framework. For example, because it has zero operating cost, rooftop solar reduces the clearing prices in wholesale energy and capacity markets. In fact, the eastern regional transmission organizations (RTOs) now account for the presence of distributed solar in calculating the RTOs' forward capacity needs, reducing capacity procurement costs. A recent analysis by ICF International found that rooftop solar will save customers in the three eastern RTOs $2 billion in capacity costs in 2019.[8]

Furthermore, solar and other DERs provide savings by reducing the cost of hedging volatile fossil fuel prices. As Edison International Chairman Theodore Craver Jr. put it during a recent Edison earnings call: "[S]ince renewables have no fuel cost, customer rates are increasingly less exposed to future natural gas price spikes. All of this helps to keep our rate increases modest and electricity affordable…"[9]

[6] "Cal-ISO Board Approves Annual Transmission Plan." California Energy Markets, April 1, 2016.
[7] PG&E, "Comments on Party Proposals and Staff Papers" filed in R. 14-07-002, Sept. 1, 2015
[8] http://www.seia.org/blog/dothemath-how-rooftop-solar-will-save-us-billions.
[9] "Edison Earning Drop, but Utility Has Rosy Outlook." California Energy Markets, May 13, 2016.

Thus, to claim a "cost-shift" by comparing the retail value of NEM credits with the wholesale energy rate, as EEI attempts to do, is to oversimplify the accounting of costs and benefits in a way that is self-serving to the utilities' interests. When the full suite of avoided costs of distributed solar are properly accounted for, rooftop solar often provides a net benefit to non-participating ratepayers, even under full retail NEM.

2.2.Studies show that benefits of rooftop solar exceed costs to ratepayers

When determining the effect of a policy on ratepayers, it is important to consider all of the costs and all of the benefits of that policy over a sufficiently long time horizon. For decades, regulators have promoted conservation programs that might increase costs for non-participating ratepayers in the short run but reduce total system costs in the long-run. Such policies have generally been considered to benefit ratepayers as a whole, in large part due to these system-wide cost reduction benefits and the elimination of rate-increasing capital additions to serve load growth.[10]

Thus, in order to determine whether net metered rooftop solar imposes net costs or benefits to non-participating ratepayers, it is necessary to conduct a comprehensive study of costs and benefits, including effects that may be hard to quantify, such as those concerning wholesale market prices and volatility. Such studies have been conducted by the federal and state governments, non-profit organizations and private firms across a number of different states over the past several years.

These studies, which are collected on the SEIA website,[11] show that in most cases, the benefits of rooftop solar exceed the costs to non-participating ratepayers. In a recent meta-analysis conducted in 2015, Environment America found that eight analyses out of 11 concluded that the value of solar energy was worth more than the average residential retail electricity rate in the area at the time the analysis was conducted. The three analyses that found different results were all commissioned by utilities.

Furthermore, a recent report by the non-partisan Brookings Institution analyzing all of the major cost-effectiveness studies to date found that net metering provides a net benefit to ratepayers. The paper finds that: "In short, while the conclusions vary, a significant body of cost-benefit research conducted by PUCs, consultants, and research organizations provides substantial evidence that net metering is more often than not a net benefit to the grid and all ratepayers."[12]

For this reason, it is important for policymakers to look beyond the simplistic framework presented by EEI that compares the wholesale energy price to the retail electric rate. A full accounting of the costs and benefits of net metering across all customer classes should be undertaken for any particular state or region before a determination is made that changes are warranted to rectify unfair cost-shifting between customers within a class of ratepayers.

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[10] Ari Peskoe, "Unjust, Unreasonable and Unduly Discriminatory: Electric Utility Rates and the Campaign against Rooftop Solar." February 1, 2016. The Texas Journal of Oil, Gas and Energy Law, 2016, Forthcoming.
[11] http://www.seia.org/policy/distributed-solar/solar-cost-benefit-studies
[12] The Brookings Institute: "Rooftop solar: Net metering is a net benefit," by Mark Muro and Devanshree Saha. May 23, 2016. http://www.brookings.edu/research/papers/2016/05/23-rooftop-solar-net-metering-muro-saha

2.3. Concern for cross-subsidies as red herring to stifle customer choice

In a recent paper entitled, "Unjust, Unreasonable and Unduly Discriminatory – Electric Utility Rates and the Campaign Against Rooftop Solar," Ari Peskoe of the Harvard Environmental policy initiative examines the utilities' arguments for rate changes in response to rooftop solar. In the paper, Peskoe observes that "[Investor owned utilities] have launched a nationwide campaign against cross subsidies, in the name of consumer protection," claiming that "failure to adopt their rate design proposals would allow subsidies between customers" and proposing rate structures that would "substantially reduce customers' incentives to generate their own electricity or buy less from the IOU."[13]

As Peskoe points out, however, a number of studies have found that "net metering's effect on rates is minimal or that decentralized PV adds sufficient value to the system to justify a compensation mechanism that does not focus exclusively on utility costs." Peskoe concludes that intra-class cross subsidies are an intentional distraction and that undue discrimination against competition should be the focus. "Several state courts have held that PUCs should align rate design with utility costs, but rate design need not be limited to matching rates with costs," says Peskoe. Furthermore, the paper states "the ultimate purpose of regulation is to protect consumers, not the IOU."

Indeed, the regulated utility has enjoyed a century of relative freedom from competition to serve small-use residential and commercial customers. Monopoly regulation was created in the 19th century to protect railroad customers from discriminatory pricing, [14] and the regulatory framework has historically served to protect customers from monopoly abuse. Regulation should enforce pricing discipline on distribution monopolies, not stifle customers' desire to invest in innovative technologies that will both lower their bills and lower system costs, while contributing to the creation of a modern, clean, and reliable grid. In weighing potential rate changes, regulators should consider the potential benefits competitive energy providers could bring to the sector through competition and innovation, and should be mindful of the customers' desire to choose technologies that allow them to manage energy costs.

3. Rate Design Should Empower Customers

By pointing to a supposed mismatch between the fixed component of utility costs and rates, EEI in its rate design Primer implies that "cost-shifting" could or should be addressed by increasing the fixed component of rates. This view is contradicted, however, by EEI's own finance expert, Peter Kind, who initially pointed out the challenges posed to utilities by DERs[15] and more recently authored a paper on grid modernization that argues against fixed charges. Kind writes:

> "Adopting meaningful monthly fixed or demand charges system-wide still reduce financial risk for utility revenue collections for the immediate future, but this

[13] Peskoe, p. 16

[14] Munn v. Illinois, 94 U.S. 113 1877

[15] Peter Kind, "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business," Edison Electric Institute. January 2013.

approach has several flaws that need to be considered when assessing alternatives. Fixed charges:

- do not promote efficiency of energy resource demand and capital investment
- reduce customer control over energy costs
- have a negative impact on low- or fixed-income customers; and
- impact all customers when select customers adopt DERs and potentially exit the system altogether, if high fixed charges are approved and the utility's cost of service increases"[16]

Kind goes on to say that "it is clear from the recent regulatory actions reconfirming support for DERs and net energy metering that policymakers are interested in DER development and customers want the option to choose their own energy supply."

In addition, state regulatory commissions have historically rejected the notion that the costs of maintaining the utility's distribution system should be included in the marginal costs attributable to individual customers for ratemaking purposes. As the Washington Utilities and Transportation Commission stated in a 1989 decision, including the costs of a "minimum-sized" distribution system in customer-related costs would "lead to the double allocation of costs to residential customers and over-allocation of costs to low-use customers." The Commission concluded: "Costs such as meter reading, billing, the cost of meters and service drops, are properly attributable to the marginal cost of serving a single customer. The cost of a minimum sized distribution system is not."[17]

Indeed, many economists share the view of the Washington Commission that only the customer-specific metering and billing costs should be considered truly fixed and thus recovered through fixed charges. "[T]he mere existence of system-wide fixed costs doesn't justify fixed charges," says University of California Professor Severin Borenstein. "We should use fixed charges to cover customer-specific fixed costs."[18]

Although this paper does not recommend a particular rate design or structure, rates that empower customers to control their energy costs and adopt new technologies while sending price signals that reduce system costs can provide benefits to all ratepayers. For example, in California, time-of-use (TOU) rates have been adopted as a feature of a new NEM tariff to incent solar customers to shift load to times of peak demand. Likewise, Peter Kind recommends TOU as an important tool "in optimizing system capacity and moderating incremental capital investment in electric energy infrastructure."

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[16] Peter Kind, "Pathway to a 21st Century Electric Utility," Ceres. November 2015.
[17] Cause U-89-2688-T, Third Supp. Order, P. 71
[18] See Borenstein, "What's so Great about Fixed Charges?" Energy Institute at Haas, November 3, 2014. https://energyathaas.wordpress.com/2014/11/03/whats-so-great-about-fixed-charges/

On the other hand, while EEI notes that demand charges have "been widely used in the industry" and suggests they may be applied to residential customers,[19] there is little evidence that doing so would produce benefits. Unlike industrial customers, residential customers have diverse loads that impose distribution system costs only in aggregate. A recent paper by the Rocky Mountain Institute concluded: "Our review finds that there is comparatively little industry experience with mass-market demand charges relative to time-based rates," the report said. "Limited empirical evidence is available to provide insight on the efficacy or impact of demand charges on any desired outcome beyond cost recovery."

In considering rate design principles, we encourage commissioners to review the Regulatory Assistance Project's 2015 handbook, "Smart Rate Design for a Smart Future," which includes the following principles:

1. Universal Service: A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
2. Usage-based Pricing: Customers should pay for grid services and power supply in proportion to how much they use these services and how much power they consume.
3. Fair Compensation: Customers who supply power to the grid should be fairly compensated for the full value of the power they supply.

4. Utility Business Model Reform is Foundational to Rate Design

Unlike unregulated industries, where companies have a financial incentive to reduce fixed costs in order to maximize profits in the face of competition, regulated utilities have the opposite incentive: the more fixed infrastructure the utilities build, the more profit their shareholders earn from their ratepayers. This "cost-of-service" ratemaking structure was well-suited to solving the challenges of an earlier time in the industry's history, when it was imperative for utilities to build out infrastructure and expand essential and reliable service across their territories.

Now that universal service has largely been accomplished, however, it is clear that the traditional cost-of-service ratemaking is at odds with a number of important policy goals. For example, while policymakers may wish to encourage conservation to keep total electric system costs low, cost-of-service ratemaking motivates utilities to continuously seek new infrastructure investments and to centralize all energy investment within the utility. This type of perverse incentive can result in the trend shown in Figure 2, where utility rate base continues to increase even as consumption remains flat.

In addition, the traditional business model might do little to ensure other goals – including improved customer service, reliability, and safety – are met. In light of the emergence of new technologies capable of reducing energy consumption and providing grid services on the customer side of the meter, regulators now need to consider whether the traditional utility business model should be adjusted.

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[19] See EEI Primer Section II a.

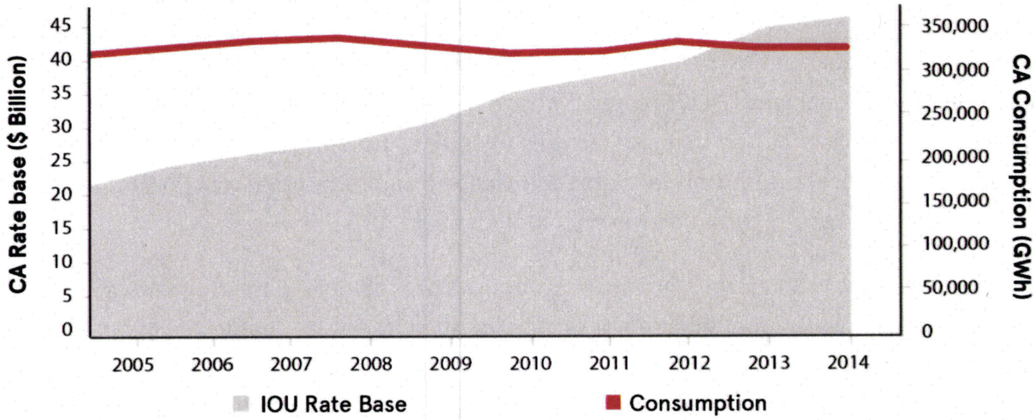

Figure 2: Trends in rate base for California investor-owned utilities[20]

4.1. DERs Should be Included in Long-Term Planning

Rooftop solar, smart inverters, battery storage, controllable appliances, networked EV chargers, and other distributed energy resources are quickly forming the basis of a modern, interconnected electric grid. These resources not only provide value to their owners, but they also have enormous potential value to the electric grid if they are appropriately incorporated into grid planning and operations.

Rather than seeking to suppress customers' demand for customer-sited DERs through rates that purport to reflect cost-causation, utilities should incorporate them into their long-term planning activities. If correctly planned for and incentivized, DERs can fill the need for both generation and distribution system investments, potentially creating significant cost savings that can reduce electricity system costs for all ratepayers.

Moreover, DERs might be better suited to meet some grid needs than traditional utility investments, which often have the quality of being "lumpy," meaning a single large investment is made now to meet future projected load growth going out decades. If the load growth does not materialize, that investment can become a stranded cost borne by all ratepayers. Even if the load growth does materialize, a single large investment made today to meet a need that may not arrive for a decade imposes an inter-generational subsidy on current ratepayers.

By contrast, customer-sited distributed resources are "modular," meaning they can be deployed gradually in very small units and geographically targeted to meet needs as they arise. Not only does this reduce the risk of stranded assets, but it also avoids the lost time-value of money associated with large lumpy investments. Just as the Vermont Public Service Board establishes geographical emphasis for energy efficiency, a forward-thinking regulator may consider geographical emphasis for other DERs.

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[20] "Electric and Gas Utility Cost Report: Public Utilities Code Section 747 Report to the Governor and Legislature", California Public Utilities Commission, April 2015; and "Energy Almanac," California Energy Commission, 2005-2014

Integrated Resource Planning activities can be a good way for utility planners to identify specific locations where distributed resources can defer planned distribution, transmission, and generation investments. Concerns about cost-shifting can be greatly reduced if utility regulators take an active role in using distributed resources to reduce total system costs. Nevertheless, regulatory planning exercises are likely not sufficient alone to overcome the utility's inherent bias toward infrastructure that can be owned and rate-based.

4.2. Revenue Decoupling Could be Implemented

Revenue decoupling is a ratemaking technique that has been used for several decades to promote energy efficiency and conservation by "disconnecting" electricity sales from utility shareholder profits. So far, 15 states have implemented revenue decoupling for electric utilities, and eight more are considering it.[21]

In states where revenue decoupling has not been implemented, utility revenue that is lost through energy efficiency, conservation or self-generation directly reduces utility shareholder profits, and utilities in these states are much less likely to promote such measures. For example, in Nevada, where electric decoupling has not been implemented, the incumbent monopoly utility, NV Energy, successfully lobbied the state PUC to implement draconian changes to net metering that have eviscerated the state's rooftop solar industry.[22] Thus, as a first step to aligning the utilities' profit motive with public policy goals promoting efficiency, conservation and self-generation, policymakers may consider revenue decoupling for utility ratemaking.

4.3. Cost-of-Service Ratemaking Should be Re-Examined

Utility regulators have long been aware of the utilities' perverse incentive to sell more electricity, which often clashes with the goals of keeping utility bills low and reducing pollution. In order to better align energy pricing with the broader societal and ratepayer goals, regulators have sought to implement policies that incent customers to conserve energy and reduce utilities' incentives to sell more power. These measures include revenue decoupling, volumetric energy pricing, inclining block tiered rates, utility energy efficiency incentives, and prohibitions on utility ownership of generation. All of these policies can benefit the public, but all run the risk of adversely affecting utility earnings unless appropriate changes are embraced in the regulatory framework.

The advent and commercialization of DERs like rooftop solar, battery storage, smart inverters, and other connected devices creates an even greater impetus to reevaluate and adjust the utility business model. The possibility of resources located on the customer side of the meter that can provide energy, capacity, ancillary services, transmission and distribution deferral, and other values creates the need for a new utility revenue mechanism that removes the natural preference for utility-owned investments over customer-owned resources that can provide the same service at a potentially lower cost.

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[21] Brookings Institute: "Rooftop solar: Net metering is a net benefit," by Mark Muro and Devanshree Saha.
[22] *Ibid.*

It is for this reason that New York and California have both opened proceedings to examine the utility business model and explore ways to reduce system costs by using customer-sited resources to defer utility infrastructure investments. Although differing in their approach, both states' efforts seek to answer the primary question facing regulators in light of the rise of DERs:

> How can the utility be properly incented to rely on customer-sited resources to meet infrastructure needs in instances where such resources would be less expensive to procure than traditional utility investments?

California Public Utilities Commissioner (CPUC) Mike Florio summarized the problem and the need for utility business model reform in a recent CPUC ruling that proposes to compensate utilities when they use DERs to defer traditional infrastructure projects.[23] "If the utility displaces or defers such investments by instead procuring DER services from others, it earns no return on the associated expenditures — such operating expenses are merely a pass-through in rates," Florio wrote. "Thus, asking the IOUs to identify opportunities for such displacements or deferrals, as we are doing in this proceeding and the [distribution resource planning proceeding], sets up a potential conflict with the company's fundamental financial objectives."

5. Conclusion

Distributed Energy Resources bring much needed technological innovation, competition, and customer engagement to the utility sector, and the benefits of these resources to both participating and non-participating ratepayers is likely to be substantial. Thus, regulators should not adopt a one-size-fits-all approach to rate design, but should instead devise solutions that are appropriate for ratepayers and also appropriately reflect state and federal energy policy goals, including:

- **Studying the impacts:** States should conduct a rigorous independent cost-effectiveness study to determine whether distributed solar under current rate structures imposes a net benefit or a net cost on all of their ratepayers and how distributed solar impacts total system costs. Policymakers can play an important role by seeking to standardize which costs and benefits are considered and how they are evaluated.
- **Modernizing utility planning:** Regulators should seek ways to incorporate solar and other DERs into utility planning so that these resources can be used to defer traditional infrastructure investments and reduce total system costs. Integrated Resource Planning and Distribution Resource Planning processes can be an effective way to accomplish this.
- **Updating utility business models:** States may consider implementing revenue decoupling, in addition to more extensive changes to utility business models and revenue mechanisms in order to provide an incentive for utilities to rely upon customer-sited DERs to meet infrastructure needs.

[23] "Assigned Commissioner's Ruling Introducing a Draft Regulatory Incentives Proposal for Discussion and Comment." California Public Utilities Commission, May 4, 2016. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M159/K702/159702148.PDF

- **Implementing technology standards:** States may wish to consider implementing technology standards developed by national or international standards-making bodies, programs, and best practices to enhance the value of the resources. For example, at 5% solar PV penetration, a state may wish to mandate solar smart inverters that can provide reactive power and voltage control as a condition of interconnecting under the NEM tariff.
- **Encouraging choice:** Regulators should design electric rates to encourage customers to choose distributed generation and foster emerging technologies that have the potential to reduce electricity costs and environmental impacts. For example, time-of-use rates can encourage customers to adopt energy storage or load-shifting technologies capable of reducing the need for central generating capacity and distribution system upgrades.
- **Gradualism, grandfathering, and predictability:** Rate changes, if deemed necessary, should be introduced gradually so that sellers of retail energy services have a stable business climate in which to operate. Existing customers should be grandfathered into pre-existing rates so as not to destroy the value of systems already installed and any new rates should be stable and predictable to ensure that customer investments can lock-in value for the life of the system.

Finally, regulators should design rates with an eye to the benefits of emerging technology and competition in the utility space. With little competition over the past 100 years, monopoly utilities have had little incentive to innovate, and the technologies used to generate and transmit electricity have changed little during that time. The emergence of distributed energy resources offers the promise of a cleaner and more competitive electric industry, providing consumers with the benefits of innovation and efficiency that accompany competitive markets. Regulators should resist allowing incumbent monopolies to use rate design as a means to squelch innovation and stifle customer choice.