Charge Without a Cause? Assessing Electric Utility Demand Charges on Small Consumers

Imposing demand charges on residential or other small customers that either the customer cannot properly respond to, or that have no relationship to controlling utility costs, are ineffective and punitive. There are simpler, better means to achieve desired objectives.

By Paul Chernick, John T. Colgan, Rick Gilliam, Douglas Jester, and Mark LeBel

Introduction & Overview

There has been significant recent attention to the possibility of including demand charges in electricity rates charged to residents and small businesses. Electric utilities historically have 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

Paul Chernick is president of Resource Insight, and has testified in some 300 regulatory and judicial proceedings. John T. Colgan is a former member of the Illinois Commerce Commission (2009-15) and has worked as a consumer advocate on energy and environmental issues. Rick Gilliam is program director of regulatory policy at Vote Solar and has long and varied experience in regulatory policy. Douglas Jester is principal of 5 Lakes Energy in Michigan and formerly advised the State of Michigan on energy policy. Mark LeBel is a staff attorney with Acadia Center in Massachusetts, where he advocates regulatory policies that advance clean distributed energy resources. Collectively, they have well over 100 years experience in regulatory policy.

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 from our review:

- 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. This means that a traditional demand charge would tend to overcharge the individual small consumer.
- Apartment residents would be particularly disadvantaged by demand charges because utilities serve the combined diversified demand of multiple apartments in a building or complex, rather than the much higher sum of individual apartment loads.
- Demand charges are complex, difficult for small customers 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 were able to respond to a demand charge by levelizing their electricity usage across broader peak periods, utilities would incur revenue shortages without any corresponding reduction in system costs.

Commented [RM1]: FROM SEAN: Is this a "technical" term or do they mean "leveling" which would be grammatically correct.

Demand charges do not offer actionable price signals to small consumers without investment in demand control technologies or very challenging household routine changes. This would result in effectively adding another mandatory fixed fee to residential and small consumer electric bills.

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 of this practice 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, in which 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

In effect, the energy charge in this rate design is $0.10/kWh, with the additional charges for the first two blocks representing an implicit demand charge. For a high load factor customer (e.g. over 400 kWh/kW, or 60% load factor), this works out to a demand charge of $0.05 × 200 + $0.02 × 200 = $14/kW. 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).

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 may be 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 lexicon, such as the following:

- **Customer peak:** Each customer experiences a non-coincident[1] peak demand (NCP) at some point in the month. That value is typically used in

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

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 each month, one of which will be the annual maximum peak. The 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 result in customers moving 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)

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

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 that 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, 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. It would also be an ineffective way of limiting the system peak.

- **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 higher costs and 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 to occur, 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 potentially more dire consequence of not responding.

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 weekday schedule, while peak system demands often occur 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 on 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) 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,

[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?

with many such 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 a matter of convenience. 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, 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. Billing demands could reflect cost causation more closely by having seasonal elements, as well as weekly and daily elements, but this increases complexity. Alternatively, demands could be measured and averaged over the 100 hours each month that contribute most to system peak loads.[4]

[4] Such a system would be more likely to capture high loads and peak demands on the system sub-

Finally, with respect to the period of measurement, if kW 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); and
- 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] Over half[8] have 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

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.

[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.

Commented [RM2]: Do they mean "level"?

customer demand often does not coincide with system demand, much of the sophisticated demand management activity by large C&I 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 each individual large customer.

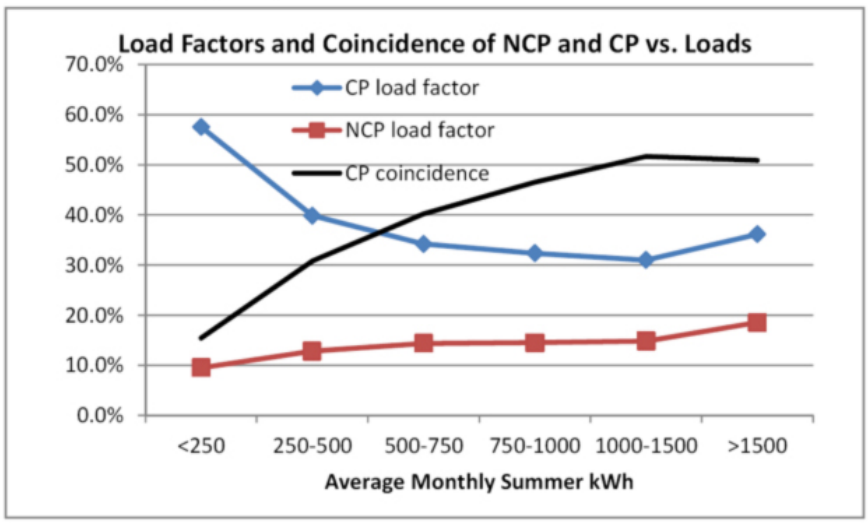
The sophisticated load management tools of large customers do not now exist for most small commercial and residential customers. These customers have a great deal of load diversity, but that diversity is not found within a single customer but among groups of customers using power at different times (see Appendix B). In these customer classes, because each customer is served through a separate meter, it is unlikely that an individual customer 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 among customers is much greater than the potential 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. The small customers' lack of ability to control individual peak demands means that a demand charge on small customers acts effectively as another fixed charge, potentially providing a more stable and consistent revenue collection vehicle for the utility than volumetric energy charges but has a needless punitive effect on small customers.

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 to fall into that category. This is 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

Figure 1, below, shows this relationship for residential customers



Source: Marcus Presentation to WCPSC, June 2015 peak periods and thus more expensive to serve. 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. See **Figure 1**.

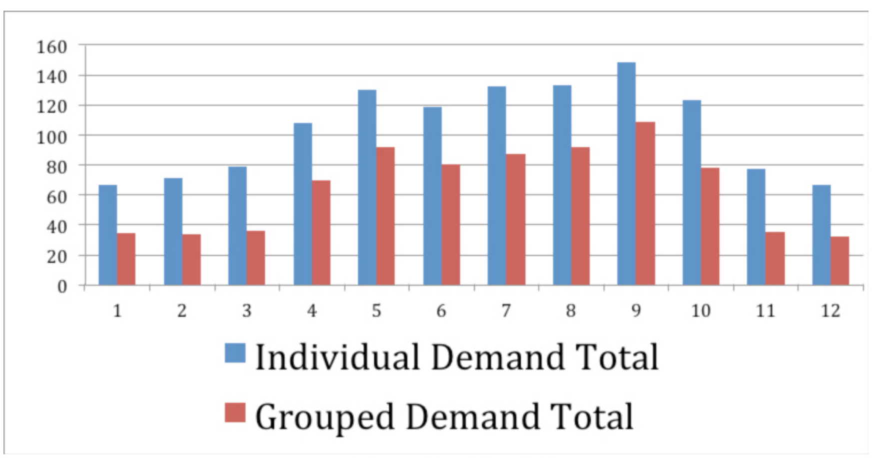
The black line (CP coincidence, or the ratio of the CP load to the NCP load) shows that customers with higher monthly energy use tend to have individual peak demands more coincident with system peak than smaller customers. The red line (NCP load factor) shows that larger-use customers have higher individual metered non-coincident load factors. The blue line (CP load factor) shows that smaller-use customers have higher 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 lack the same degree of opportunities to take advantage of behind the meter load diversity. Although they have many small appliances that often operate for short periods of time, it takes but a few operating simultaneously to establish a significant 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 and do 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,

Commented [RM3]: Not clear what "CP"

Figure 2: Individual vs. Grouped Demand Total



Source: RAP Demand Charge Webinar, Dec. 2015 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 each apartment, but the combined (diverse) demand of the building or complex. Figure 2 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.

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 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 patterns that the customer would able 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: there is no discernible cost causation relationship between individual customers' peak demand and system peak.

Metering costs and allocation

Demand charges require more complex and expensive metering technologies than conventional two-part tariffs. The cost-effectiveness of any such upgrades should be analyzed on its own merits; but 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]

Demand charges as a price signal

Imposition of demand charges on residential customers runs counter to the ratemaking principles of simplicity, understandability, public acceptability, and feasibility of application. It would be a formidable task 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 that "[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

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

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 demand charge only serves as 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) are likely to have load factors higher than the class average and thus benefit from demand charges. Rather than contributing to fixed-cost recovery for each of the many kWh they use, these customers would pay a smaller share of those costs through their relatively low billing demand. Conversely, low-usage customers — including low-income customers — would likely pay more on average.[13]

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. The following summary addresses each criterion.

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.

   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

[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.

[13] Similar effects occur within with the larger commercial and industrial classes, as well. Demand charges shift costs from high load-factor to low load-factor customers.

Arizona Public Service Co. case study below.)

Feasibility of application: While measuring customer maximum demand is technically feasible, new metering equipment would be required for most small customers. The likely metering technology is smart meters, which can also be used for more appropriate time-varying rates. 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 cannot 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 under collection 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 would 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 to do so.

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, placing 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 vs. off-peak electricity, Pullman travel vs. coach travel, single party telephone service vs. service from a multi party line, etc.).

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 would reduce the customer's incentive to reduce consumption and result 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 Co.'s 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 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 APS case study 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."[14] 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.[15]

There is important history here. In the late 1980s, 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 that the Arizona Corporation Commission (ACC) created with the inclining block rate design. APS markets the demand rate only to large-use customers who they believe 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.[16] So it is a self-selected subclass of customers with above-average usage, above-average diversity, and most likely above-average financial resources. Results from this subset should not be assumed to apply to behavior or experience of other subclasses.

Use of the rate comparison tool for self-selection infers that those APS residential customers who chose to take service under 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 generally 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 a price signal is even sent. To the contrary, the fact that APS has marketed its optional demand charge rates for over 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 have decided that it is not the best option for them.

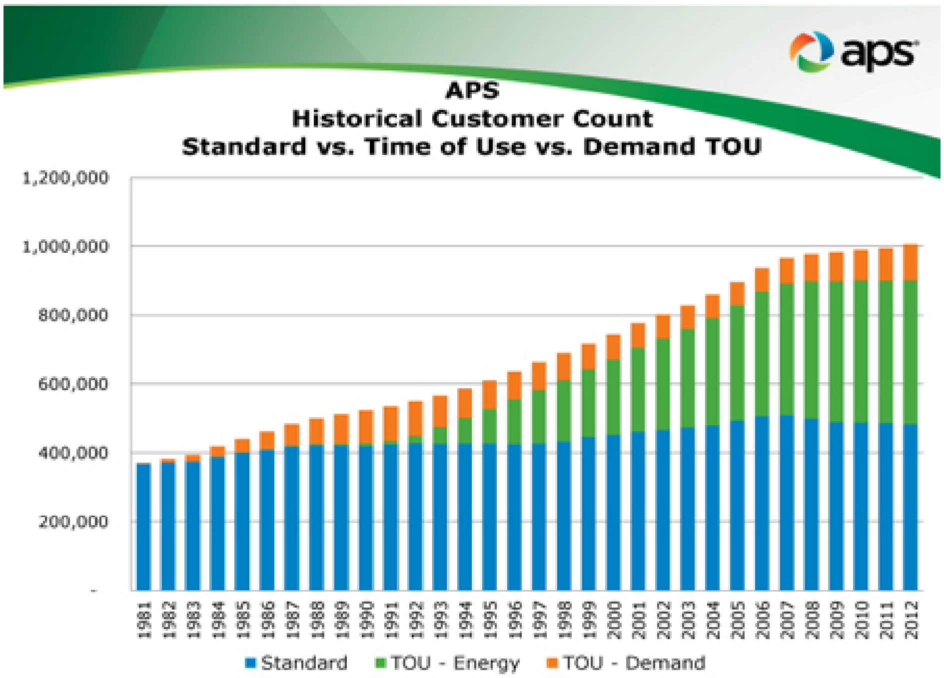
In a recent rate proceeding, APS revealed that as many as 40% of its customers that recently switched from a two-part rate to the optional

[14] 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.

[15] *Id.* at 7.

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

demand charge rate actually increased their maximum on-peak demand. This means that even among 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 *optional* 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

Electricity Journal

- *Moving Towards Demand-based Residential Rates*, Scott Rubin, Nov. 2015
- *Legal Case against Standby Rates*, Casten & Karegianes, Nov. 2007

E source survey: *Net Metering Wars: What Do Customers Think?*: http://b.3cdn.net/solarchoice/27dbacad2a21535d4c_78m6ber20.pdf

Natural Gas and Electricity Magazine: *Residential Demand Charges*, Feb. 2016: 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, Aug. 2014: https://nccleantech.ncsu.edu/wp-content/uploads/Rethinking-Standby-and-Fixed-Cost-Charges_V2.pdf

Regulatory Assistance Project

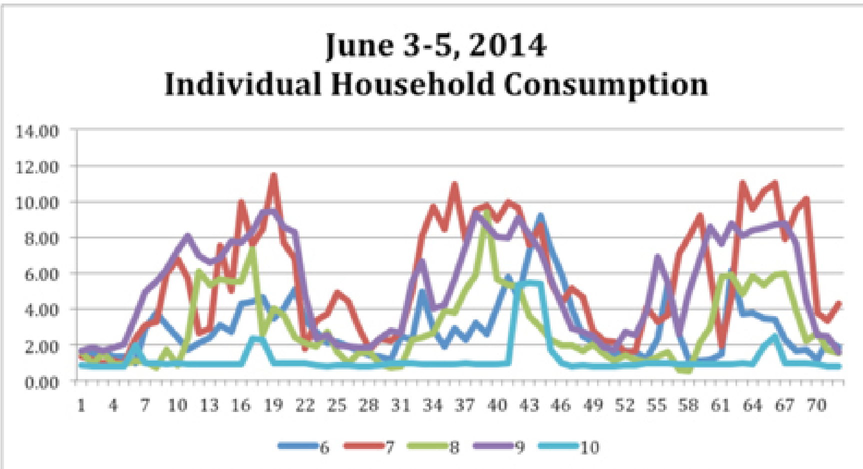
- Smart Rate Design for a Smart Future: https://www.raponline.org/document/download/id/7680
- Designing DG Tariffs Well: http://www.raponline.org/document/download/id/6898
- Use Great Caution in the Design of Residential Demand Charges: http://www.raponline.org/document/download/id/7844
- *Electric Utility 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

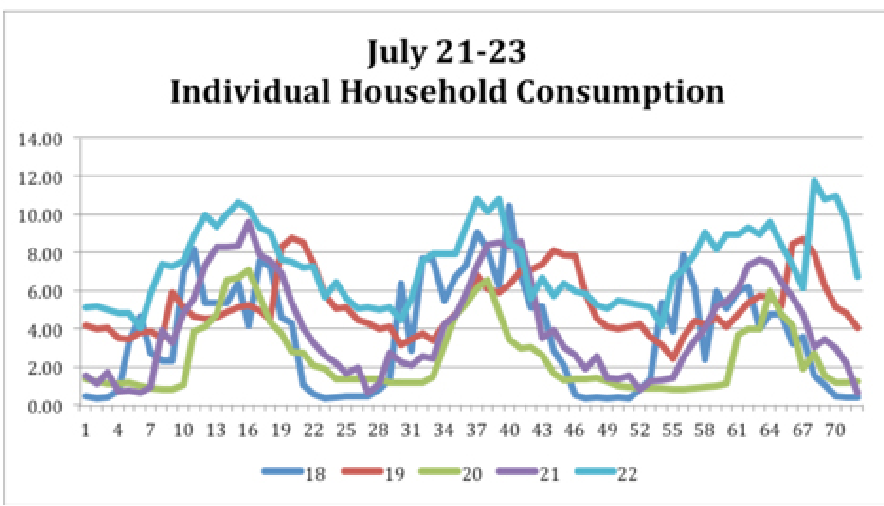
- A Review of Rate Design Alternatives: http://www.rmi.org/alternative_rate_designs

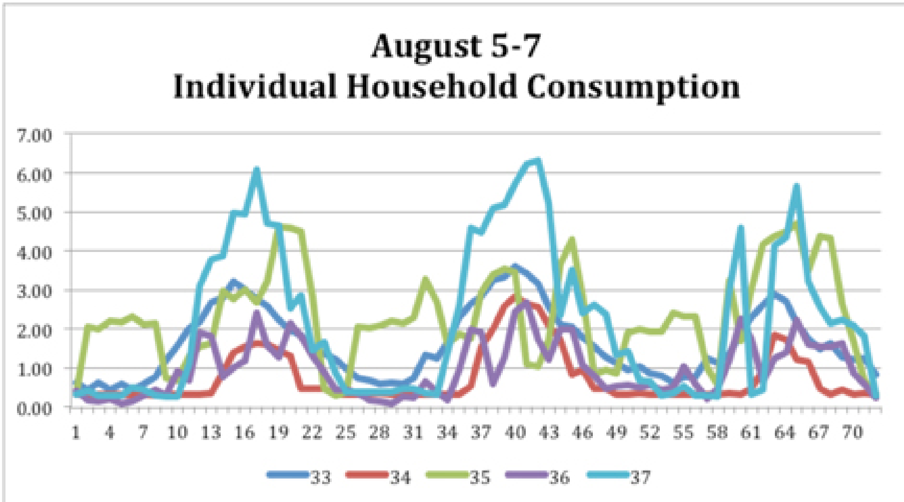
Appendix B: Sample Individual Residential Customer Loads

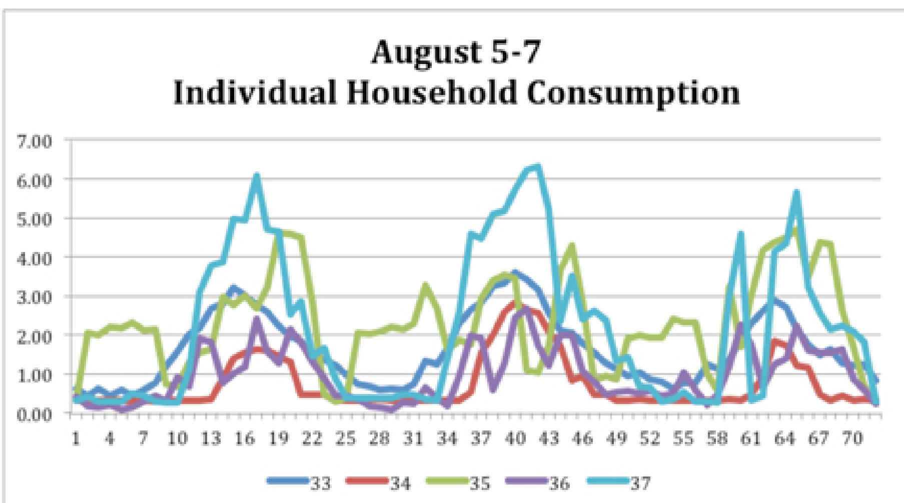
New Mexico

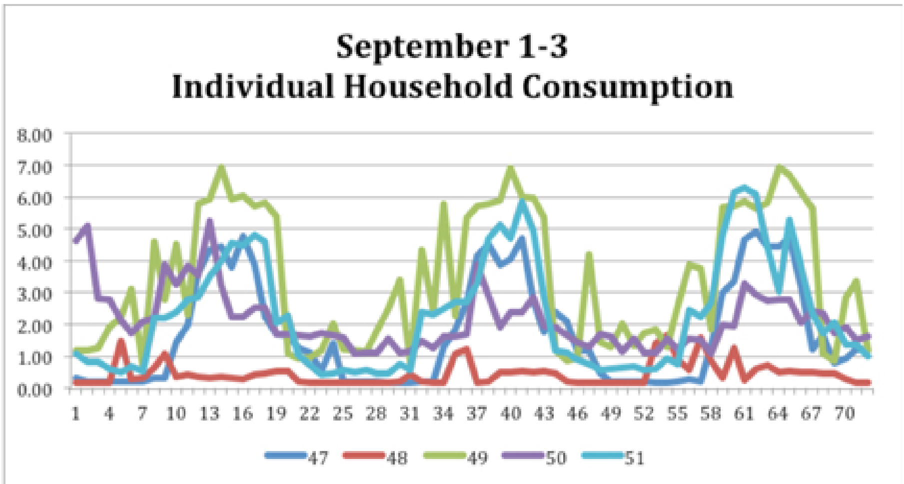


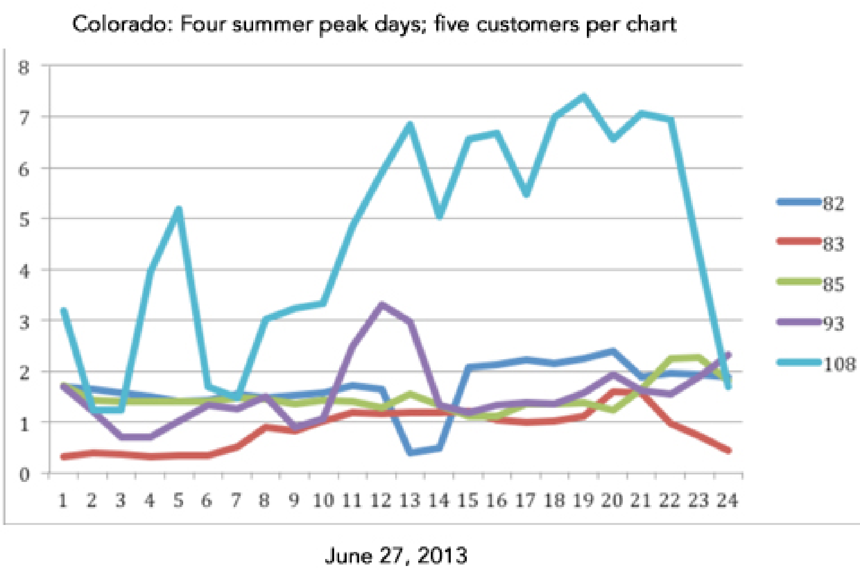
Four summer peak periods; three days and five customers per chart
(middle day is system peak day)

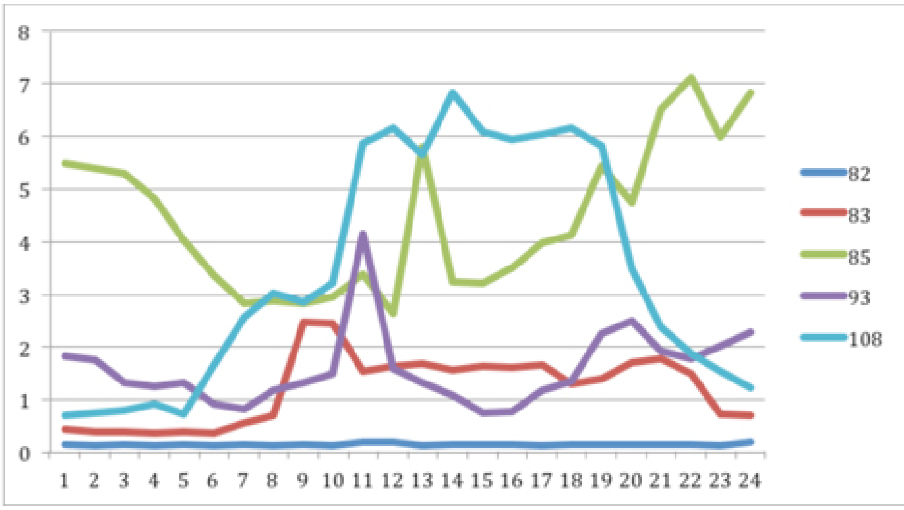



August 5-7
Individual Household Consumption
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1 4 7 10 13 16 19 22 25 28 31 34 37 40 43 46 49 52 55 58 61 64 67 70
33 34 35 36 37

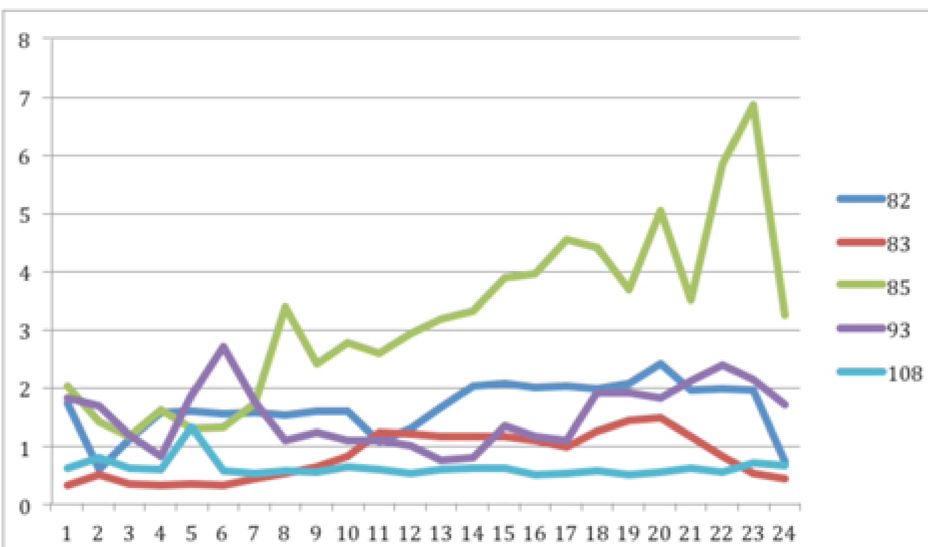

August 5-7
Individual Household Consumption
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1 4 7 10 13 16 19 22 25 28 31 34 37 40 43 46 49 52 55 58 61 64 67 70
33 34 35 36 37


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

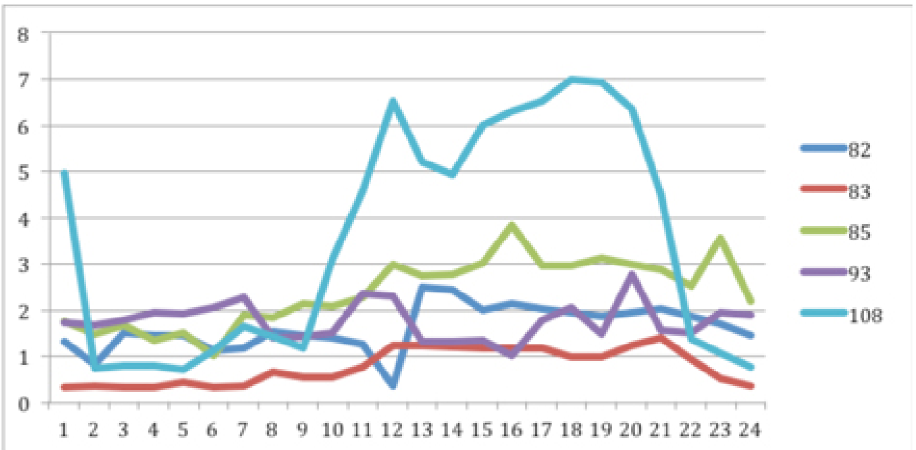

Colorado: Four summer peak days; five customers per chart
8
7
6
5
4
3
2
1
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
82
83
85
93
108
June 27, 2013



July 11, 2013



August 20, 2013



September 6, 2013