Rate Design for DER Customers in New York

A Way Forward

PRESENTED TO

VDER Rate Design Working Group

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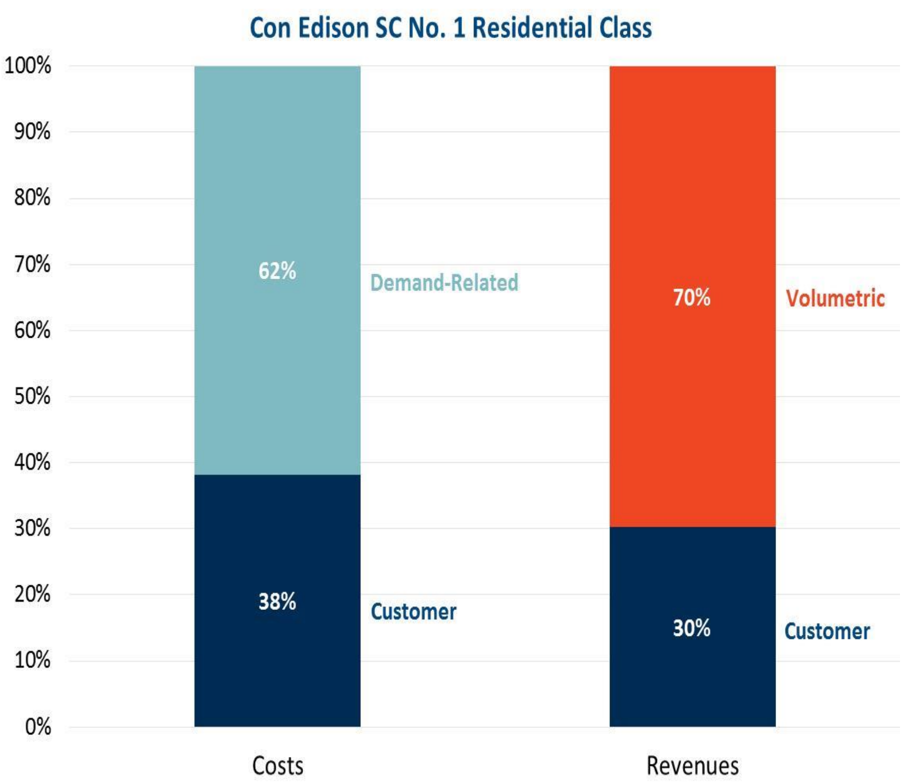
THE Brattle GROUP

Agenda

For many utilities, residential rates and costs are misaligned

Delivery revenues vs. costs Con Edison Residential (SC 1)	Why is this important?



- Delivery costs are mainly fixed and demand related, but a significant portion of delivery revenue is recovered through volumetric charges
- It is critical to shift delivery rate design to a more cost-based rate structure to drive efficient customer behavior

A rate design revolution is all but inevitable

Problems caused by the volumetric rate structure

- Falling load factors, driven by rising peak loads and falling sales
- DERs will continue to exacerbate the mismatch between revenue and costs among residential customers

Regulatory directive

- Push for increased DER penetration, greater customer choice, and greater system efficiency

Changing customer needs

- Seamless integration of technologies with the grid (rates not a barrier) at the same level of reliability they have today
- Expect customized and personalized rate options

Staff Whitepaper on ratemaking has clearly articulated the need for change

“Changing electricity system and REV make it necessary to reevaluate conventional rate design and DER compensation mechanisms. These factors together imply valuable opportunities, as well as a risk of negative impacts for customers if rate designs are not optimized”

- REV will result in much greater adoption of DERs, many of which may displace more traditional infrastructure investments.
- The decisions supporting the investments should be as economically sound as possible in order to effectively lower total cost

“Efficient price signals and transparency are hallmarks of a successful market”

- Rate design and compensation mechanisms that accomplish these will help to optimize the investment in and use of DER, thereby reducing total system costs and customer bills, not only for customers with DERs
- Rates that are bundled and mask the underlying costs of service will not facilitate efficient decisions

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Alternative Rate Designs

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Other Policy Objectives

Conclusions

PSC-Approved Rate Design Principles

Principles	Objective
1. Cost Causation	• Rates should reflect cost causation, including embedded costs, long-run marginal and future costs
2. Encourage Outcomes	• Rates should encourage desired market and policy outcomes in a technology neutral manner
3. Policy Transparency	• Incentives should be explicit and transparent, and should support state policy goals
4. Decision-making	• Rates should encourage economically efficient and market-enabled decision-making, for both operations and new investments, in a technology neutral manner.
5. Fair Value	• Customers and utility should both be paid the fair value for the grid services they provide
6. Customer Orientation	• Rates should be practical, understandable and promote choice
7. Stability	• Customer bills should be relatively stable
8. Access	• Electricity should remain affordable and accessible for vulnerable sub populations
9. Gradualism	• Rate changes should be implemented in a manner which would not cause any large bill impacts
10. Economic Sustainability	• Rate design should reflect a long-term approach to price signals and remain neutral to any particular technology or business cycle

Rates are the means by which costs are assessed on customers

In a competitive market, economic efficiency is maximized because prices end up equaling marginal cost

- However, electric utilities are regulated monopolies and do not face a competitive market
- In an unregulated space, monopolies will maximize profits by setting prices at customers' willingness to pay
- In a regulated space, rates are designed to approximate a competitive market. This maximizes the distribution of economic welfare to producers and consumers
- Therefore, rates of a regulated monopoly should be cost-based

The premise of cost-based rates is discussed in the seminal work by James Bonbright (Principles of Public Utility Rates)

Bonbright on cost causation

He argued that a purely volumetric rate assumes that the total costs of the utility vary directly with the changes in the kWh output of energy. He calls this "a grossly false assumption" and says such a rate "violates the most widely accepted canon of fair pricing, the principle of service at cost

- "One standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and public opinion alike – the standard of cost of service, often qualified by the stipulation that the relevant cost is necessary cost or cost reasonably or prudently incurred."
- While discussing the Hopkinson rate, he says that "such a rate distinguishes between the two most important cost functions of an electric-utility system: between those costs that vary with changes in the system's output of energy, and those costs that vary with plant capacity and hence with the maximum demands on the system (and subsystems) that the company must be prepared to meet in planning its construction program."

Bonbright on three-part rates

Bonbright believed that three-part rates mirrored the structure of utility costs and cited their widespread deployment to medium and large commercial and industrial rates. In support of three-part rates, he cited an earlier text by the British engineer D. J. Bolton, which states:

- "More accurate costing has shown that, on the average, only one-quarter of the total costs of electricity supply are represented by coal or items proportional to energy, while three-quarters are represented by fixed costs or items proportional to power, etc. If therefore only one rate is to be levied it would appear more logical to charge for power and neglect the energy."

The utility cost structure has three primary components

Utility Cost Structure		
Customer Related Costs	**Grid Related Costs**	**Supply Related Costs**
• Minimum system • Meter • Service line • Transformer • Customer care	• Distribution grid • Transmission grid	• Fuel costs • Power plants (capacity)

Current residential delivery rates typically have two components to recover a multitude of utility service costs: fixed charges and volumetric rates

An ideal rate structure would attribute a separate charge to address each of the cost categories

- Supply related costs still matter in a deregulated state like NY, and mass market rate design problem should also be considered for supply

A five-part rate would reflect costs accurately

A Fully Cost-Based Rate			
	Fixed Cost ($/month)	**Demand Charge ($/kW-month)**	**Volumetric Charge ($/kWh)**
Distribution	✓	✓	
Transmission		✓	
Generation		✓	✓

An ideal rate structure would attribute a separate charge to address each of the cost categories

However, as much as rates should promote economic efficiency and equity, the changes in rate regimes should be implemented gradually and the <u>complexity of the rates should be balanced against their likely customer understanding</u>

Delivery Costs: fixed vs. variable?

While many delivery costs are fixed in the short-term, others are variable in the long-term

- Several components of the distribution system represent infrastructure for connecting customers to the grid 24/7 and are fixed costs in nature
  - Service drops, line transformers, poles and conductors
  - While some of these fixed costs can be recovered through customer charges, some are best recovered via a demand charge based on customer's *non-coincident peak demand* or the size of the customer's connection

- There are other components of the distribution system with costs that vary in the long term based on the capacity used
  - Substations, transmission, etc.
  - Cost of these components can be recovered via a *coincident peak demand* charge

A three-part rate would provide a good approximation to the five-part rate

For distribution-only utilities, this translates into a two-part rate, where the first part is a (fixed) service charge and the second part is a demand charge; for other utilities, into a three-part rate, where the third part is an energy charge

1. **Customer charge ($/month)** designed to recover "customer-related" fixed costs

2. **Demand charges ($/kW-month)** designed to recover costs of providing capacity. It can be designed to have two components based on the fixed vs. variable cost nature of the capacity
   - A non-coincident peak demand charge for being connected 24/7 to the grid
   - A coincident peak demand charge for using the capacity

3. **Energy charge ($/kWh)** designed to recover the variable costs of generating electricity

Source: Alliance to Save Energy, "Forging a Path to the Modern Grid" (February 2018)

Design considerations for demand charges

Duration of the demand interval (15, 30 or 60 minutes)

Measurement of demand (maximum day, top three days, or average of all days)

Coincident peak (CP) vs. Non-coincident peak (NCP)

- If non-coincident, restricted to a peak window or not

Nature of coincidence (with system peak, transmission peak or local distribution peak)

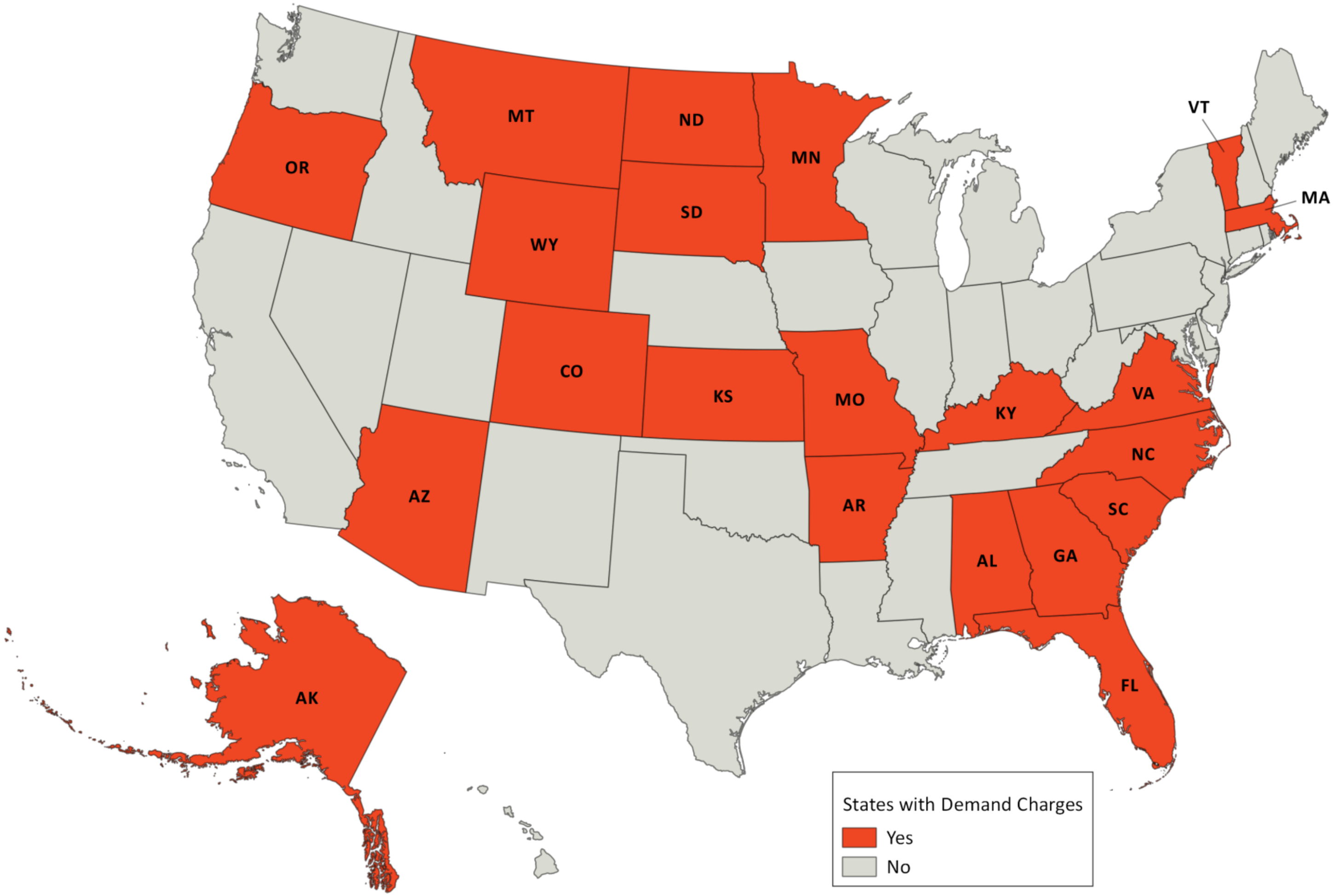
Cost-causation vs. ease of implementation

Introduction of ratchets or not

Demand can be measured using CP or NCP

	Coincident Peak	Non-coincident Peak
Pros	• Is effective in addressing delivery capacity costs further away from the customer • It directly addresses local capacity constraints if coincident with local distribution peak • It can be measured during a defined peak window	• Is effective in addressing delivery capacity costs close to the customer (grid access charge) • Customers may develop rules of thumb to manage their max demand
Cons	• Difficult to manage as the time of CP is not known until the end of the month • If coincident with system peak, may not address local distribution peak constraints	• Management of NCP does not necessarily address delivery capacity costs further away from the customer

50 utilities in 21 states offer residential demand charges



Source: The Brattle Group, January 2018. See Appendix for details.

Currently, most deployments of demand charges are for DER customers only

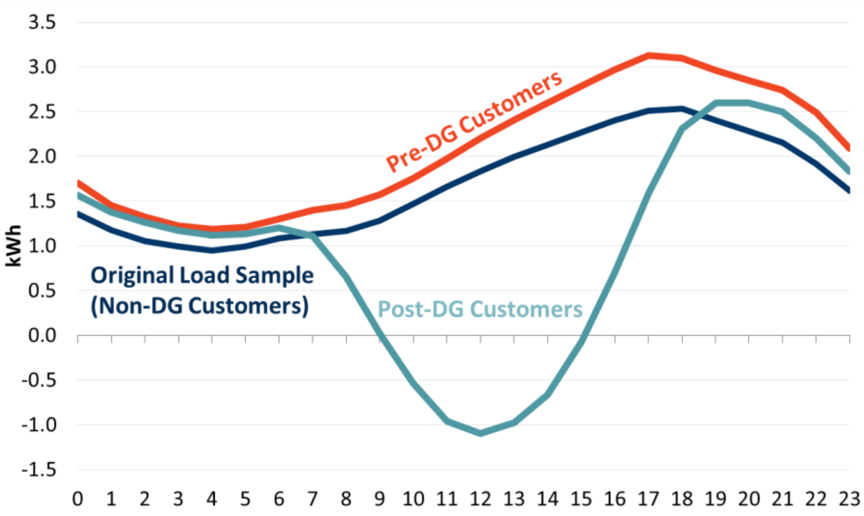
Most utilities prioritize moving DER customers to demand charges to alleviate the primary cost-causation problem

Utilities such as Eversource, Arizona Public Service, Salt River Project, NV Energy, and Westar Energy have filed applications to make demand charges mandatory tariff for customers with DER

- The MA DPU has recently approved mandatory demand charges for all new net metering facilities for residential and small commercial customers of Eversource
- Salt River Project in Arizona, a municipally owned system, has instituted a mandatory tariff for DG customers
- The Kansas Corporation Commission has ordered that DG customers be considered a separate class and be offered three-part rates, among other options

These utilities define DG customers as a separate class as their load shapes differ from non-DG customers

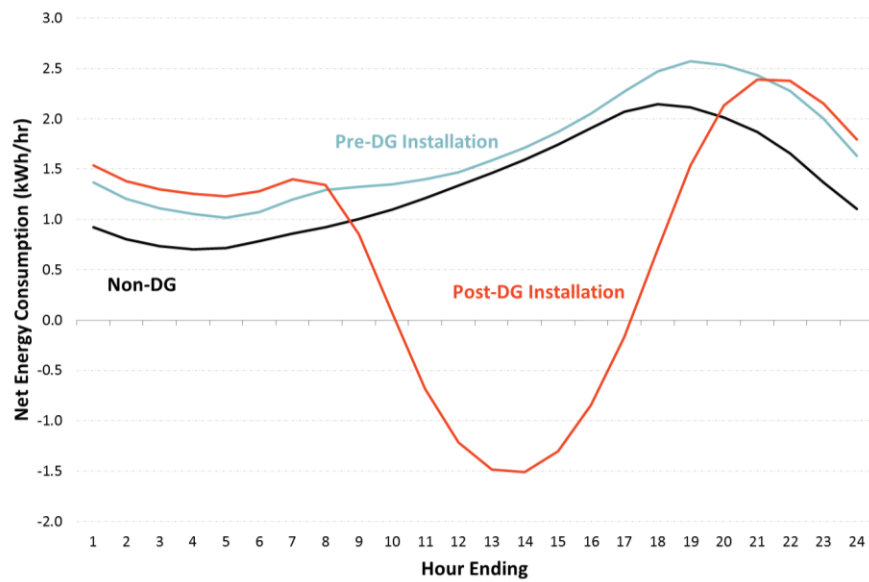
Summer Load Shape Comparison, Kansas



Source: Westar DG Customer Data.

- We find DG reduces net energy consumption by half from **1060 kWh** to **530 kWh**
- However, average monthly peak demand is virtually unchanged

Summer Load Shape Comparison, Idaho



- We find DG reduces net energy consumption by over a third from **1190 kWh** to **770 kWh**
- As in Kansas, average monthly peak demand is virtually unchanged

There are pros and cons for implementing three-part rates for DER customers only

Pros

- Fewer customers to deal with
- Can argue that DER customers constitute a separate rate class
- Draw analogy with pricing for partial requirements service

Cons

- Risk being attacked on grounds of discriminating between customers
- There are multiple forms of DER which, when implemented individually or in combination, may presumably require a complex array of DER rates
- DERs are not the only thing that makes customer usage profiles different from each other (e.g., customer lifestyle, behavior)

Most of these utilities recognize the need to move all mass-market customers to 3-part tariffs eventually

Currently some utilities offer 3-part tariffs on a voluntary basis to all mass market customers

- APS has more than 120,000 customers on an opt-in 3-part tariff and through a new rate settlement, will offer three more demand charges to accommodate different customer sizes
- Black Hills Power, Georgia Power, OG&E

Most utilities with mandatory demand charges for DER customers recognize that 3-part tariffs may very well be appropriate for all mass market customers

This is consistent with the New York approach to mass-market rate reform. DER customers are the priority (Staff's effort to develop an NEM successor tariff) with the recognition that rate reform is necessary for all mass market customers

Compensation for DER injections is distinct from rate design

Net Energy Metering

- Export at the retail rate (e.g., California, New Hampshire, Nevada, Michigan)
- Phase 1 NEM approach

Net Billing

- Export at the market price (e.g., Arizona, Hawaii)
- Value Stack Tariff (export at Locational Marginal price + Capacity Value + Environmental Value + Market Transition Credit)

Buy All, Sell All (BASA)

- Export at the market price, but requires dual meters (Maine)

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Utilities and commissions have chosen several pathways to move beyond the 2-part rate

Introduce demand charges	• APS, OG&E, SRP (DER customers), and Westar (DER customers)
Introduce TOU energy charges	• CPUC directive to California IOUs by 2019, OG&E's Smart Hours rate, and Ontario's regulated rate plan*
Increase fixed charges	• NV Energy (DER customers), Omaha PPD, SMUD, and Texas*
Do nothing	• Sit tight and hope that the storm will blow over

*Indicates restructured utilities

Alternative Delivery Rate Designs for DER Customers I

Rate Design	Main Features	Other Considerations
Demand Charges	• Reflects delivery related cost-causation • Typically require interval meters • Ideally would have two components: CP and NCP demand	• Several options are available for measuring demand (NCP is most common) • In some cases, billing demand is measured during the peak window
TOU Rates	• TOU periods are determined based on system or local load conditions • May have seasonal definitions	• As the peak shifts towards later in the day, it becomes more effective in recovering demand related costs
CPP Rates	• Typically declared based on wholesale system conditions, although there are variations based on local conditions	• CPP can be defined as a demand charge or a kWh charge • Event day charge may vary across events (VPP)
Seasonal/Tiered Pricing	• Seasonal rates to reflect higher commodity or delivery rates in high demand seasons • First tier typically determined to cover essential uses	• Tiered rates typically have weak cost causation • Declining or inclining
Increased Fixed Charge	• Reflects fixed costs of serving customers • Most fixed charges do not include all customer costs; some utilities increase fixed costs to cover all customer related costs and some demand related costs	• May have a larger negative impact on low usage customers • May temper conservation incentives • Easier to manage from customer experience perspective

Alternative Delivery Rate Designs for DER Customers II

Rate Design	Main Features	Other Considerations
Subscription Service	• Fixed delivery charge based on kW usage subscription level • Single charge for all delivery costs • Additional charge for excess demand	• Customers may choose subscription levels or they are defaulted based on historic consumption levels • Variations around demand measurement
Minimum Bill	• Ensures that each customer makes a minimum level of contribution to cost recovery regardless of their consumption • May negatively impact low usage customers	• Minimum level of consumption needs to be determined
Grid Access Charge	• Charge per kW of solar generating capacity • Ensure that solar customers contribute to the recovery of delivery costs regardless of their net consumption	• Need to determine the basis of grid access charge (inverter rating, max net demand) • Need a technology specific access charge
Stand-by Rates	• No volumetric charges included • Customer charge, contract demand charge, daily as-used demand charge	• Which costs to include in contract demand vs. as-used demand? • Measurement of as-used demand • Additional charge for actual demand that exceed the contract demand

Performance of alternative rate designs in satisfying rate design principles

Principles	Volumetric Rate	Demand Charges	Volumetric TOU	Stand-by Rates	Higher Fixed Charges	Minimum Bills
1. Cost Causation	Weak	Strong	Medium	Strong	Strong	Weak
2. Encourage Outcomes	Medium	Strong	Medium	Strong	Medium	Weak
3. Policy Transparency	Weak	Strong	Strong	Strong	Strong	Medium
4. Decision-making	Weak	Strong	Strong	Medium	Weak	Weak
5. Fair Value	Weak	Strong	Medium	Medium	Weak	Weak
6. Customer Orientation	Strong	Medium	Medium	Medium	Weak	Weak
7. Stability	Strong	Medium	Medium	Medium	Strong	Strong
8. Access	Medium	Medium	Medium	Medium	Weak	Weak
9. Gradualism	Strong	Strong	Strong	Strong	Strong	Strong
10. Sustainability	Weak	Strong	Medium	Strong	Medium	Weak

Strong Medium Weak

Is there an ideal rate design for DER customers? I

Rate design for DER customers should adhere to the same Commission accepted rate design principles that would apply to mass market customers in general

Several alternatives can be assessed with respect to their conformity to the Commission accepted rate design principles

It is difficult to find the "ideal rate design" that would hit the mark on all ten principles

- To the extent that certain principles have a larger weight compared to others, that should help with the determination of the ideal rate design given the circumstances

Is there an ideal rate design for DER customers? II

High priority rate design principles

- *Cost-based rates* lead to economically efficient outcomes and remove hidden subsidies that may lead to over/under consumption of electricity or over/under investment in certain technologies
  - Volumetric delivery rates are not cost based and lead to cross-subsidies between DG and non-DG customers
  - Inclining block rates are not cost based and lead to larger customers subsidizing smaller customers
- *Economic sustainability* ensures that rates convey efficient price signals in a technology neutral manner
- *Customer orientation* ensures that the rates are understandable and promote choice
  - Customer education is an essential driver of customer orientation

Are TOU rates good substitutes for demand charges? I

Volumetric TOU rates are presented as an alternative to demand charges to ensure that the peak capacity costs are correctly attributed to those who are contributing to peak demand

- This might be generally true for recovering generation and transmission capacity costs since they tend to be driven with the system peak hours
- However, distribution capacity costs do not necessarily correlate well with the system peak
- Therefore, while a DER customer is reducing their usage in response to the TOU rates (perhaps via self-generation) and reducing peak G&T requirements, it doesn't mean that they are also reducing D capacity requirements. It may in fact mean that they are underpaying for the distribution costs

Failure of DG, or increased demand for other reasons, has little consequence under a volumetric TOU rate

- Utility system still needs to be built to provide the customer's full load when such failures or demand increases occur

Are TOU rates good substitutes for demand charges? II

Defining the TOU peak period to be consistent with the distribution peak brings TOU rates closer to demand charges, however the recovery of costs associated with 24/7 grid access service is still not guaranteed under this approach

- When solar penetration reaches a certain level, system load shape changes, and the peak window shifts towards later in the day (duck curve phenomenon)
- In this case, self generation during the new peak window would be much limited, therefore customers with solar PVs are not able to avoid higher peak TOU charges as they used to

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Can residential customers understand demand charges?

Anyone who has purchased a light bulb has encountered watts; ditto for anyone who has purchased a hair dryer or an electric iron

Customers often introduced to kWh's by way of kWs; *e.g.*, if you leave on a 100 watt bulb for 10 hours, it will use 1,000 watt-hours, or one kWh

Similarly, if you run your hair dryer at the same time that someone else is ironing their clothes and lights are on in both bathrooms, the circuit breaker may trip on you since you have exceeded its capacity

Customers don't need to be electricity experts to understand a demand charge

Responding to a demand charge does not require that the customers know exactly when their maximum demand will occur

- If customers know to avoid the simultaneous use of electricity-intensive appliances, they could easily reduce their maximum demand without ever knowing when it occurs
- This simple message should be stressed in customer marketing and outreach initiatives associated with the demand rate

Examples from utility websites

- APS: "Limit the number of appliances you use at once during on-peak hours"
- Georgia Power: "Avoid simultaneous use of major appliances. If you can avoid running appliances at the same time, then your peak demand would be lower. This translates to less demand on Georgia Power Company, and savings for you!

Staggering the use of a few appliances could lead to significant demand reductions—one customer's data

Avg. Demand Over 15 min

Appliance	Avg. Demand (kW)	
Clothes Dryer	4.0	Flexible Load (18.5 kW)
Oven	2.0	
Stove	1.0	
Hand iron	0.5	
Central air conditioner	5.0	
Spa heater and filter	6.0	
Misc. plug loads	0.2	Inflexible Load (1 kW)
Lighting	0.3	
Refrigerator	0.5	
Total	19.5	

Comments

- Use of some of the appliances is inflexible (1 kW)
- Use of other appliances could be easily staggered to reduce demand
- Simply delaying use of the clothes dryer, oven, stove, and hand iron would reduce the customer's maximum demand by 7.5 kW
- This would bring the customer's maximum demand down to 12 kW, a roughly 38% reduction in demand

Observations about existing demand rates I

There is no one-size-fits-all approach across the various offerings

- Several vary by season
- Some combined with time-varying energy charge
- Several based on demand during system peak period
- A few measure demand over a 60 minute interval

Mostly offered on opt-in basis, occasionally mandatory for sub-classes

Emerging trend toward enhanced marketing

Low enrollment but not necessarily due to lack of interest

Observations about existing demand rates II

Reasons for offering the rates have changed

- Older rates: Improve load factor (opt-in)
- Newer rates: More equitable cost recovery (opt-in)
- Future rates: Equity and fairness, (opt-out or mandatory)

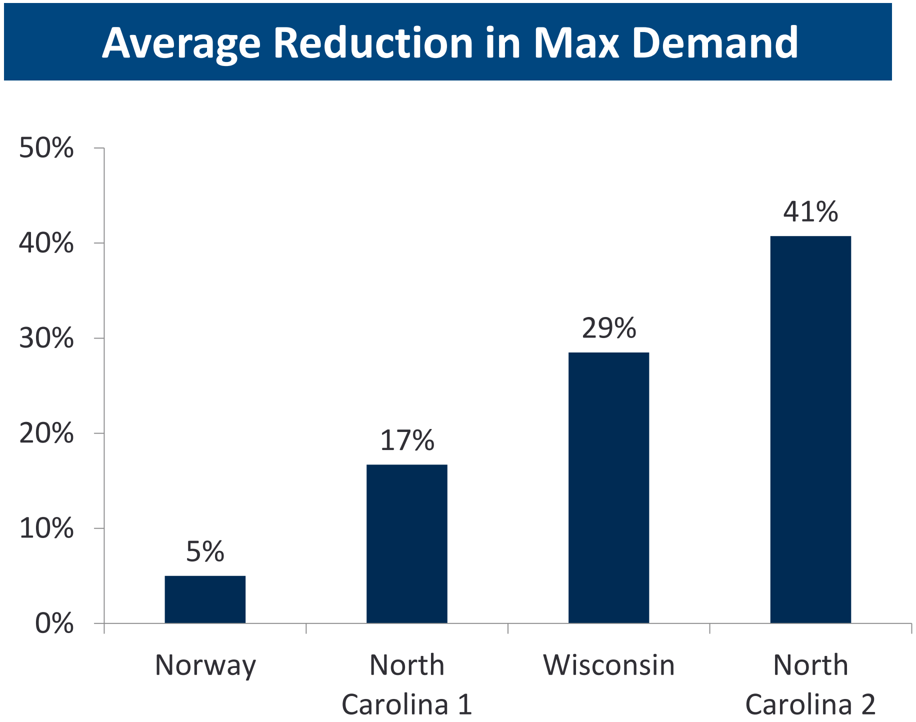
Most utilities are vertically-integrated (not in ISOs/RTOs) or coops

Rates typically recover distribution and generation capacity costs and sometimes transmission

Little empirical assessment of the rates' impacts on customer behavior has been conducted

- Most of the existing research is outdated (see next slide)

Do residential customers respond to demand charges?



Note: The North Carolina pilot was analyzed through two separate studies using different methodologies; both results are presented here

Until recently, there were only three (outdated) studies that looked into this question

- Three experiments suggest that customers will respond, however these studies are outdated
- The impact estimates vary widely and based on small sample sizes
- No clear correlation between the demand charge level and participants' demand reduction
- New research is needed

Evidence from 2nd Generation Programs/Pilots

APS has more than 120,000 customers subscribed to utility's residential demand rate

- 3-parts (TOU energy, demand, and fixed charge)
- Both energy and demand components have seasonal variation
- Highest integrated one-hour kW read during peak hours
- Customers on a demand-based TOU rate shave peak demand by 5–15% more compared to customers on an energy only TOU rate

SRP is currently running a pilot program to understand the impact of demand charges on the non-DG residential customer usage

Xcel Energy is currently undertaking a residential pilot that tests TOU rates and demand charges side by side

Con Edison is developing a residential demand charge pilot

However, sometimes pilots are not feasible

While some jurisdictions carefully study the implications of demand charges in the form of pilots, others have circumstances that prevent them from undertaking these pilots

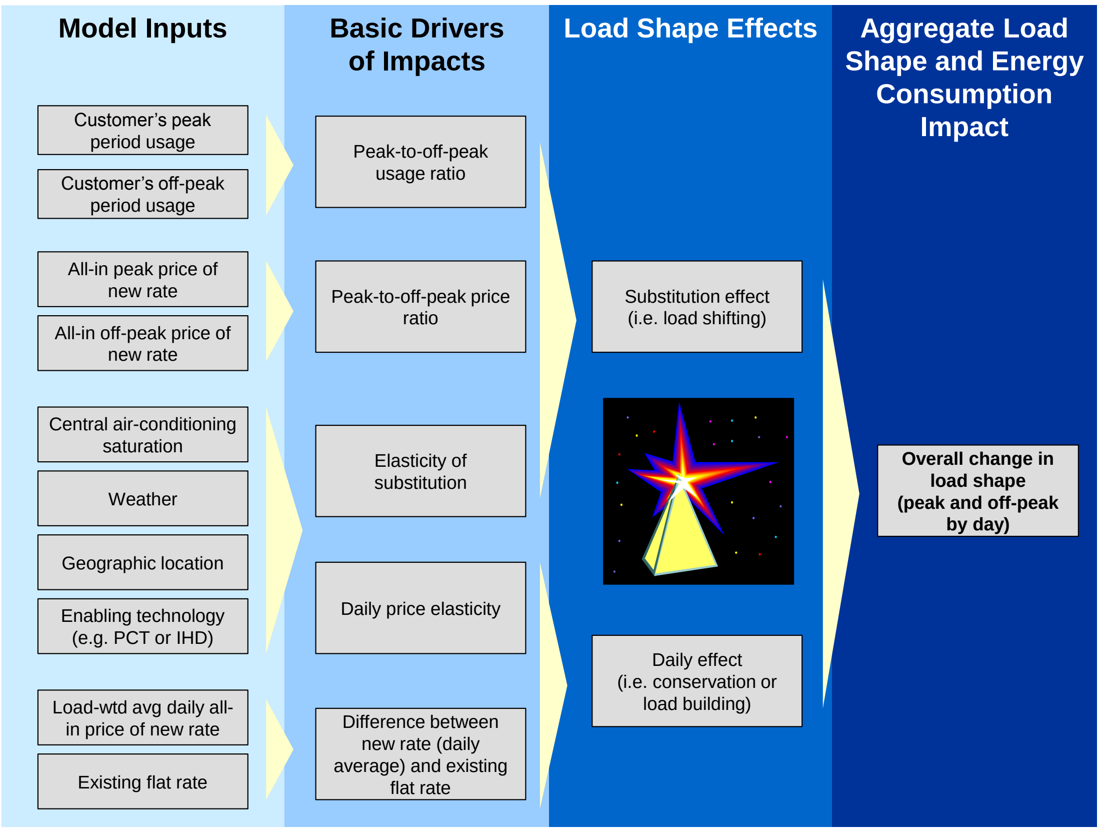
In the latter case, it might be useful to rely on an analytical tool to study:

- How does the demand change with different levels of demand charges?
- Does the impact vary for different customer types?
- How do the demand and peak impacts compare to each other under different pricing schemes?

We adapted the PRISM model to quantify the impact of demand charges

Brattle's PRISM Model Applied to Demand Charges

Illustration of System-based Approach



Comments

- Load shifting effect and the average price effect can be represented through a single system of two simultaneous demand equations
- This modeling framework has been used to estimate customer response to time-varying rates in California, Connecticut, Florida, Maryland, and Michigan, among other jurisdictions
- In California and Maryland, the resulting estimates of peak demand reductions were used in utility AMI business cases that were ultimately approved by the respective state regulatory commissions

Impacts from Demand Charge vs. TOU Rate

We model the impacts from two revenue neutral rates:

TOU vs. Demand Charge

- Demand charge is defined based on the highest one hour demand in the peak period
- Customer A is small but peaky
- Customer B is average
- Customer C is large and less peaky

	Current Pricing	Time of Use Pricing	Residential Demand
Customer Charge ($/month	$10.00	$10.00	$10.00
Volumetric Charge ($/kWh)	$0.10		$0.05
Peak (4PM - 8PM)		$0.30	
Off-Peak		$0.07	
Demand Charge ($/kW)			$8.00

Sample Usage Patterns				
	Peak Usage	Off-Peak Usage	Demand	Total
Customer A	80	300	5	380
Customer B	150	850	4	1000
Customer C	250	2250	3	2500

Impact of Residential Demand Charge

With the implementation of demand charges:

- For Customer A (small but peaky customer), the demand is lower by 16.6% after the implementation of RDC
- For Customer B (average customer), the demand is lower by 11.8%
- For Customer C (large and less peaky customer), the demand is lower by 7.1%

For Customers A and B, TOU peak impact is lower compared to demand charge impact

- Caution against generalization that demand charges lead to higher impacts compared to TOU rates

Customer A	Time-of-Use	Residential Demand Charge
Total Usage	-0.6%	-1.5%
Peak Usage	-10.0%	
Demand		-16.6%

*Demand is measured in kW, all else in kWh.

Customer B	Time-of-Use	Residential Demand Charge
Total Usage	-0.2%	0.8%
Peak Usage	-11.3%	
Demand		-11.8%

*Demand is measured in kW, all else in kWh.

Customer C	Time-of-Use	Residential Demand Charge
Total Usage	0.3%	2.1%
Peak Usage	-12.0%	
Demand		-7.1%

*Demand is measured in kW, all else in kWh.

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Certain stakeholders object to demand charges on the following grounds

Demand charges will increase bills for low income customers

- Unproven claim; no evidence is available at this point

Residential customers will not understand demand charges

- There are proven ways to simplify demand charges for customers (*i.e.*, messaging around staggering usage of energy intensive appliances)

They will remove the incentive to invest in energy efficiency and rooftop solar PV

- Rates should not be used to incentivize any technologies in the first place

They will require unnecessary investments in billing infrastructure

- Smart meter deployment will already require enhancements to the billing infrastructure

The Transition Path

Utilities will need to adopt new tactics to facilitate a smoother roll-out

- Proactively seek stakeholder input in designing the rates
- Market the new rate using multiple channels including social media
- Monitor customer reactions and make appropriate changes in messaging, *i.e.*, “test and learn” in real time

Minimize the adverse impact on customer bills by doing one or more of the following

- Change rates gradually
- Educate customers on how to respond to demand charges

Customers acceptance of demand charges will be enhanced by several complementary drivers

Wide scale customer outreach and education campaigns

Utility enabled tools and programs

- Web portals
- Text and email alerts
- Energy efficiency initiatives:
  - More efficient appliances, weatherization
  - Awareness
- Programmable communicating thermostats
- Direct load control

Customer investment in new technologies

- Battery storage
- End-use disaggregation products

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The PSC has adopted the “Economic Sustainability” principle to rate design

Rate design should reflect a long-term approach to price signals and remain neutral to any particular technology or business cycle

Rate design should mainly be used to convey efficient price signals, and not to select one technology over the other (*e.g.*, to promote efficient charging of EVs)

This is especially true when technologies move past the nascent stage

- Impact on solar—solar costs are declining so rate subsidies no longer appropriate
- Energy efficiency is already supported by state and utility funds, so no need for rate subsidy

Concluding Thoughts I

Volumetric rates do not provide efficient or equitable price signals to residential customers

- They create cross-subsides between customers with different load factors and in particular between customers with DG and those without DG
- The problem will become more pronounced as DG penetration grows

Choice of appropriate mass market rate design should not be decided solely on customer bill impacts

- Bill impacts can inform the pace of change
- The principles of cost causation and economic sustainability should be given priority

Concluding Thoughts II

For electric delivery service, the combination of a fixed customer charge and a demand charge best align revenues and costs and provide customers with the appropriate price signals. Demand charge can be:

- A combination of non-coincident peak and coincident peak demand charges; or
- Time-differentiated demand charges

There are many ways in which to make the transition

- Phase in rate reform with initial focus on DG customers
- Seek stakeholder input
- Educate customers

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Appendix
Current Residential 3-Part Tariff Offerings I

#	Utility	Utility Ownership	State	Demand interval	Combined with Energy TOU?	Applicable Residential Segment	Mandatory or Voluntary
[1]	Alabama Power	Investor Owned	AL	15 min	Yes	All	Voluntary
[2]	Alaska Electric Light and Power	Investor Owned	AK	Unknown	No	All	Voluntary
[3]	Albemarle Electric Membership Corp	Cooperative	NC	15 min	Yes	All	Voluntary
[4]	Arizona Public Service	Investor Owned	AZ	60 min	Yes	All	Voluntary
[5]	Arizona Public Service	Investor Owned	AZ	60 min	Yes	All	Voluntary
[6]	Black Hills Power	Investor Owned	SD	15 min	No	All	Voluntary
[7]	Black Hills Power	Investor Owned	WY	15 min	No	All	Voluntary
[8]	Butler Rural Electric Cooperative	Cooperative	KS	60 min	No	All	Mandatory
[9]	Carteret-Craven Electric Cooperative	Cooperative	NC	15 min	No	All	Voluntary
[10]	Central Electric Membership Corp	Cooperative	NC	15 min	Yes	All	Voluntary
[11]	City of Fort Collins Utilities	Municipal	CO	Unknown	No	All	Voluntary
[12]	City of Glasgow	Municipal	KY	30 min	Yes	All	Voluntary (opt-out)
[13]	City of Kinston	Municipal	NC	15 min	No	All	Voluntary
[14]	City of Longmont	Municipal	CO	15 min	No	All	Voluntary
[15]	City of Templeton	Municipal	MA	15 min	No	All	Mandatory
[16]	Cobb Electric Membership Cooperative	Cooperative	GA	60 min	No	All	Voluntary
[17]	Dakota Electric Association	Cooperative	MN	15 min	No	All	Voluntary
[18]	Dominion Energy	Investor Owned	NC	30 min	Yes	All	Voluntary
[19]	Dominion Energy	Investor Owned	VA	30 min	Yes	All	Voluntary
[20]	Duke Energy Carolinas, LLC	Investor Owned	NC	15 min	Yes	All	Voluntary
[21]	Duke Energy Carolinas, LLC	Investor Owned	SC	30 min	Yes	All	Voluntary
[22]	Edgecombe-Martin County EMC	Cooperative	NC	Unknown	No	All	Voluntary
[23]	Eversource Energy	Investor Owned	MA	60 min	No	DG only	Mandatory
[24]	Fort Morgan	Municipal	CO	Unknown	No	All	Voluntary
[25]	Georgia Power	Investor Owned	GA	30 min	Yes	All	Voluntary

Source: The Brattle Group, January 2018.

Appendix
Current Residential 3-Part Tariff Offerings II

#	Utility	Utility Ownership	State	Demand interval	Combined with Energy TOU?	Applicable Residential Segment	Mandatory or Voluntary
[26]	Kentucky Utilities Company	Investor Owned	KY	15 min	No	All	Voluntary
[27]	Lakeland Electric	Municipal	FL	30 min	No	All	Voluntary
[28]	Louisville Gas and Electric	Investor Owned	KY	15 min	No	All	Voluntary
[29]	Loveland Electric	Municipal	CO	15 min	No	All	Voluntary
[30]	Mid-Carolina Electric Cooperative	Cooperative	SC	60 min	No	All	Mandatory
[31]	Midwest Energy Inc	Cooperative	KS	15 min	No	All	Voluntary
[32]	Oklahoma Gas and Electric Company	Investor Owned	AR	15 min	No	All	Voluntary
[33]	Otter Tail Power Company	Investor Owned	MN	60 min	No	All	Voluntary
[34]	Otter Tail Power Company	Investor Owned	ND	60 min	No	All	Voluntary
[35]	Otter Tail Power Company	Investor Owned	SD	60 min	No	All	Voluntary
[36]	PacifiCorp	Investor Owned	OR	Unknown	No	All	Voluntary
[37]	Pee Dee Electric Cooperative	Cooperative	SC	Unknown	Yes	All	Voluntary
[38]	Platte-Clay Electric Cooperative	Cooperative	MO	60 min	No	All	Mandatory
[39]	Progress Energy Carolinas	Investor Owned	NC	15 min	Yes	All	Voluntary
[40]	Salt River Project	Political Subdivision	AZ	30 min	Yes	DG only	Mandatory
[41]	Santee Cooper Electric Cooperative	Cooperative	SC	30 min	Yes	DG only	Mandatory
[42]	Smithfield	Municipal	NC	15 min	Yes	All	Voluntary
[43]	South Carolina Electric & Gas Company	Investor Owned	SC	15 min	Yes	All	Voluntary
[44]	Swanton Village Electric Department	Municipal	VT	15 min	No	All	Mandatory
[45]	Tri-County Electric Cooperative	Cooperative	FL	15 min	No	All	Voluntary
[46]	Traverse Electric Cooperative, Inc.	Cooperative	MN	Unknown	No	All	Voluntary
[47]	Vigilante Electric Cooperative	Cooperative	MT	Unknown	No	All	Mandatory
[48]	Westar Energy	Investor Owned	KS	30 min	No	All	Voluntary
[49]	Xcel Energy (PSCo)	Investor Owned	CO	15 min	No	All	Voluntary
[50]	Xcel Energy (PSCo)	Investor Owned	CO	60 min	No	All	Voluntary

Source: The Brattle Group, January 2018.

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Dr. Sergici has been at the forefront of the design and impact analysis of innovative retail pricing, enabling technology, and behavior-based energy efficiency pilots and programs in North America. She has led numerous studies in these areas that were instrumental in regulatory approvals of Advanced Metering Infrastructure (AMI) investments and smart rate offerings for electricity customers. She also has significant expertise in development of load forecasting models; ratemaking for electric utilities; and energy litigation. Most recently, in the context of the New York Reforming the Energy Vision (NYREV) Initiative, Dr. Sergici studied the incentives required for and the impacts of incorporating large quantities of Distributed Energy Resources (DERs) including energy efficiency, demand response, and solar PVs in New York.

Dr. Sergici is a frequent presenter on the economic analysis of DERs and regularly publishes in academic and industry journals. She received her Ph.D. in Applied Economics from Northeastern University in the fields of applied econometrics and industrial organization. She received her M.A. in Economics from Northeastern University, and B.S. in Economics from Middle East Technical University (METU), Ankara, Turkey.