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DC Public Service Commission
Rate Design Working Group
Meeting Minutes – Fourth Meeting (4/9/25)

Agenda

1. Welcome
2. DOEE Presentation
3. Next Steps

Participating Organizations: Pepco, OPC, Grid 2.0, DOEE, GSA, AOBA, WMATA, Commission Staff.

Welcome and Housekeeping

Staff welcomed working group members. DOEE agreed to take and circulate draft minutes for the working group meeting.

DOEE and Synapse Presentation

DOEE's consultant, Melissa Whited from Synapse, presented on time of use rates from around the country and included a straw proposal for a path forward for residential TOU rates and initial considerations regarding commercial TOU rates.

The presentation first reviewed the treatment and analysis of of TOU rates in Clean Energy DC (2018) and the PSC's Value of Distributed Energy Resources (VDER) study. The presentation then reviewed research and examples of TOU rates from around the country, noting such findings as TOU rates are common across the country, opt-in rates tend to have low enrollment, and research shows that TOU rates can be effective for load shifting, particularly for EV load. The presentation next reviewed some of the history of TOU rates in DC starting in the 1980s proceeding through to the current R-PIV and MDU-PIV rates.

DOEE next presented on overarching considerations for TOU design, describing advantages and disadvantages of opt-in and opt-out models, different price differentials for peak and off-peak pricing, and other key considerations like promotion of customer understanding and ensuring cost effective implementation by weight costs against benefits.

DOEE presented analysis regarding optimal timing of TOU rates in DC, based on distribution load profiles and peak PJM LMP and capacity hours. The analysis shows that the highest LMPs tend to be from 3-8pm in the summer, and the PJM peak capacity hours tend to occur from 4-6pm.

DOEE presented its straw proposal for residential rates, based in providing two opt-in rates (one whole house residential TOU rate and one EV specific rate) with peak hours of 4-9pm. DOEE's straw proposal includes starting with simpler TOU rates and considering more advanced rates (e.g. critical peak pricing or locational adders) as a next phase of work, after adopting simpler TOU rates. DOEE's proposal also includes a formal evaluation framework to understand benefits and impacts of TOU rates and determine whether to transition to an opt-out/default rate model for residential customers at some point in the future. Finally, DOEE presented initial considerations that could inform TOU rate design for commercial customers, focusing on reducing the barriers proposed by

traditional design of demand charges. DOEE noted that it does not have at this time a full straw proposal for commercial TOU rates.

Discussion Following DOEE Presentation

Commission staff explained how before retail choice, the majority of customers utilized time of use rates, but that changed with restructuring in the 90s. In light of retail choice, Commission staff asked how generation should be incorporated into TOU design. DOEE highlighted the potential value of reducing wholesale market costs though noted that currently SOS suppliers do not seem to be reflecting TOU cost differences.

Commission staff also highlighted prior pilots in DC on dynamic pricing (e.g. critical peak pricing, and hourly price signals) and asked DOEE how dynamic pricing should fit into the plans for TOU rates. DOEE noted that DOEE is a strong supporter of critical peak pricing, which research shows can result in higher load shifting, but currently recommends starting with simpler TOU rates, particularly on the residential side. The working group could consider starting with dynamic pricing sooner on the commercial side if there is interest.

Working group members asked what consideration has been given to the BSA and decoupling, and how cost savings could occur with decoupling. DOEE explained that from a distribution infrastructure perspective, some savings could materialize through deferred or avoided infrastructure that would otherwise have been needed. Additional cost savings could be realized through reduced capacity and energy prices, though those may take some number of months and years to flow through to customers depending on, for example, how SOS procurement is structured.

Commission staff also asked how TOU pricing could be incorporated in utility programs like those proposed in FC1160. DOEE noted that implementation steps are key and that a variety of programs, including those managed by DOEE and DCSEU, could take advantage of TOU rates. Commission staff also asked about the pros and cons of opt-out rates when it comes to critical peak pricing. DOEE noted that ensuring high customer awareness and engagement is key for critical peak pricing, and that may be harder to realize with an opt-out/default model.

Working group members noted the value of a repository to see where DC has been and where we are going when it comes to TOU offerings. Working group members noted the importance of tracking change and evaluating both the TOU rates (e.g. their cost efficacy) and the underlying market dynamics, which we know change over time. DOEE agreed that a formal evaluation is important with an agreed upon timeline. Working group members also asked whether this proposal is moving fast enough to help the District meet its climate goals. DOEE explained that it's important to balance moving expeditiously with designing a sound program that gets customer acceptance and buy in over time.

Other working group members stated that success of time varying rates depends on investments in education and outreach, and asked what research DOEE has done into education and outreach. Synapse and DOEE explained that marketing and outreach is key, noting various tools and techniques that other jurisdictions have utilized, e.g. that individualized emails or post cards can be more successful than a generic online advertisement. DOEE noted there is a need to balance investments in those programs against their expenses. Synapse said that some states, like

California, have had success with working groups bringing together best practices in customer outreach and education.

Working group members also asked about the advantages of designing time of use rates for different classes or sub-classes of customers, e.g. based on load profiles for all-electric customers or NEM customers. DOEE explained that it's important to design a rate based on underlying system costs, so there may be limits on how many different price structures one would want to offer. But DOEE also noted that the working group could look to specific TOU rates that can, for example, promote storage and load shifting for certain customers.

Working group members next asked for clarity regarding how TOU rates would help with PJM capacity auction prices, explaining that the VRR demand curve is relatively fixed. DOEE explained that the impact on PJM prices may take time to see, but comes from how PJM calculates both overall regional capacity needs, specific capacity supply obligations for particular zones, and finally the market clearing price. DOEE explained, for example, that PJM's methodology for calculating capacity supply obligations based on the 5 peak hours of usage from each local zone, so reducing usage at those 5 peak hours can help reduce capacity costs for the Pepco zone as a whole. DOEE also noted that because of how the clearing price is set, relatively small changes in demand – particularly in combination with other states that are using TOU rates and other demand reduction tools – can be significant. But DOEE stated that it would be helpful to have an expert walk through the full methodology used to calculate overall capacity supply obligations for the Pepco zone and the allocation of those costs between Pepco DC and Pepco MD.

Working group members next asked how we would ensure that benefits actually flow to residents, and whether for example actual substations or distribution system investments would be avoided. DOEE noted that it is critical to have an evaluation framework for TOUs – and any demand-reduction program – to measure impacts and ensure that we are realizing real benefits for customers, relative to the implementation costs.

Working group members also expressed concern for commercial customers, both in terms of overall costs that they have been bearing recently, as well as the uncertainties around commercial load usage in light of federal layoffs, agency relocation, and other market dynamics affecting the commercial real estate industry in DC. Working group members expressed concerns regarding added costs and in particular any experimentation tied to projected load growth, which may or may not occur. Working group members noted that because Pepco's profits are tied to capital investments, there is a particularly difficult challenge in having demand reduction measures result in actual capital cost savings. DOEE agreed that it is critical to make sure that benefits actually do flow through to consumers and that any demand reduction strategy needs to be paired with other actions, like strong oversight of utility capital investments, to ensure actual overall cost reductions.

Working group members expressed appreciation for the menu of options approach that DOEE suggested, and asked about whether having a short on-peak window and a larger shoulder period may make sense. Working group members also stated that it could be helpful to learn from other jurisdictions, like California and Oklahoma, and have a member of Pepco's capacity planning team and explain how peak demand reduction (including from TOU rates) could impact capacity costs.

<u>Next Steps</u>

The working group tentatively agreed upon 10am on Friday, May 2nd for the next meeting date. Working group members can submit proposed agenda topics to the Commission staff by COB Friday (4/11). DOEE will share draft minutes this Friday, edits are due Tuesday, 4/15 and DOEE will file the final copy by Friday 4/18.

TOU Rate Design in the District of Columbia

Key considerations and a straw proposal

Presentation to the Rate Design Working Group

April 9, 2025

Melissa Whited, Synapse Energy Economics

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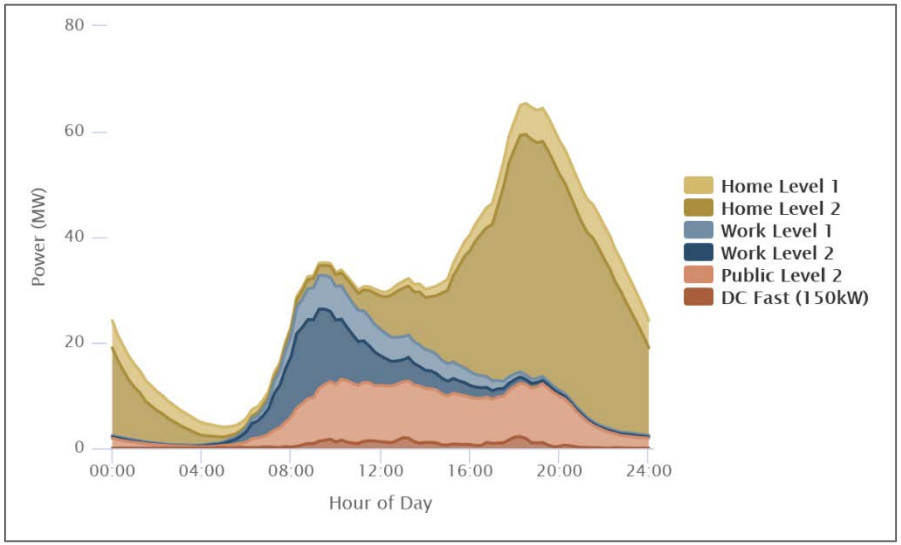
Context – TOU and electrification load

- The District's Clean Energy DC Plan aims to reduce emissions by 56% in 2032 relative to 2006, with electrification of end-uses being a key component of the plan.
- The District's Transportation Electrification Roadmap: transition to zero-emission vehicles by 2045, with at least 25% of vehicles registered in DC zero-emission by 2030
- Meeting DC's electrification goals could result in significant additional load during peak hours

Potential EV Charging Load Curve

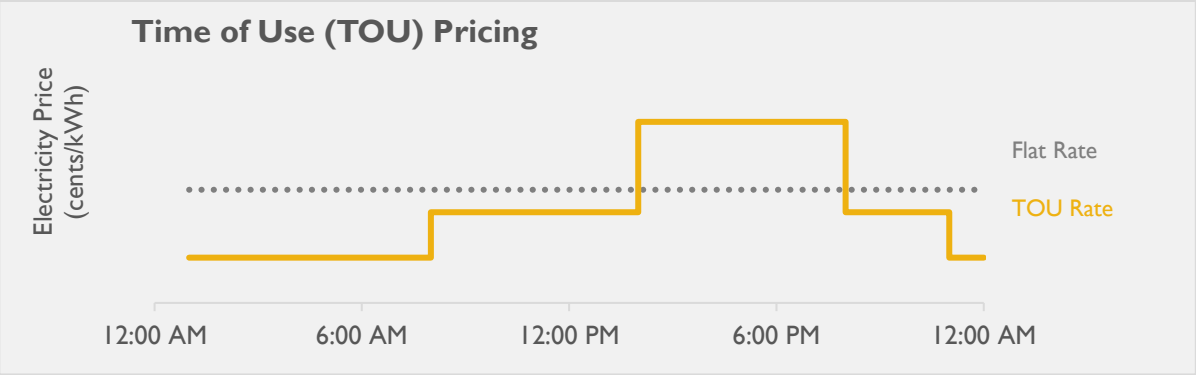


Source: U.S. Department of Energy, EVI-Pro Lite tool output, assuming 77,000 EVs by 2030

TOU to mitigate peak load increases

- The 2023 Value of DER study recommended implementing time-varying rates to encourage customers to shift electricity usage to lower-cost times, thereby reducing system-wide costs, as a "low-cost, no-regrets measure."
  - "Rates of varying complexity can be offered to customers with different levels of sophistication… For example, whole-house TOU rates can be offered alongside locational CPP rates (where the timing of peak events varies by location according to local distribution needs.) Further, EV customers could be allowed to separately meter their EV load, which may encourage more customers to sign up for the rate."

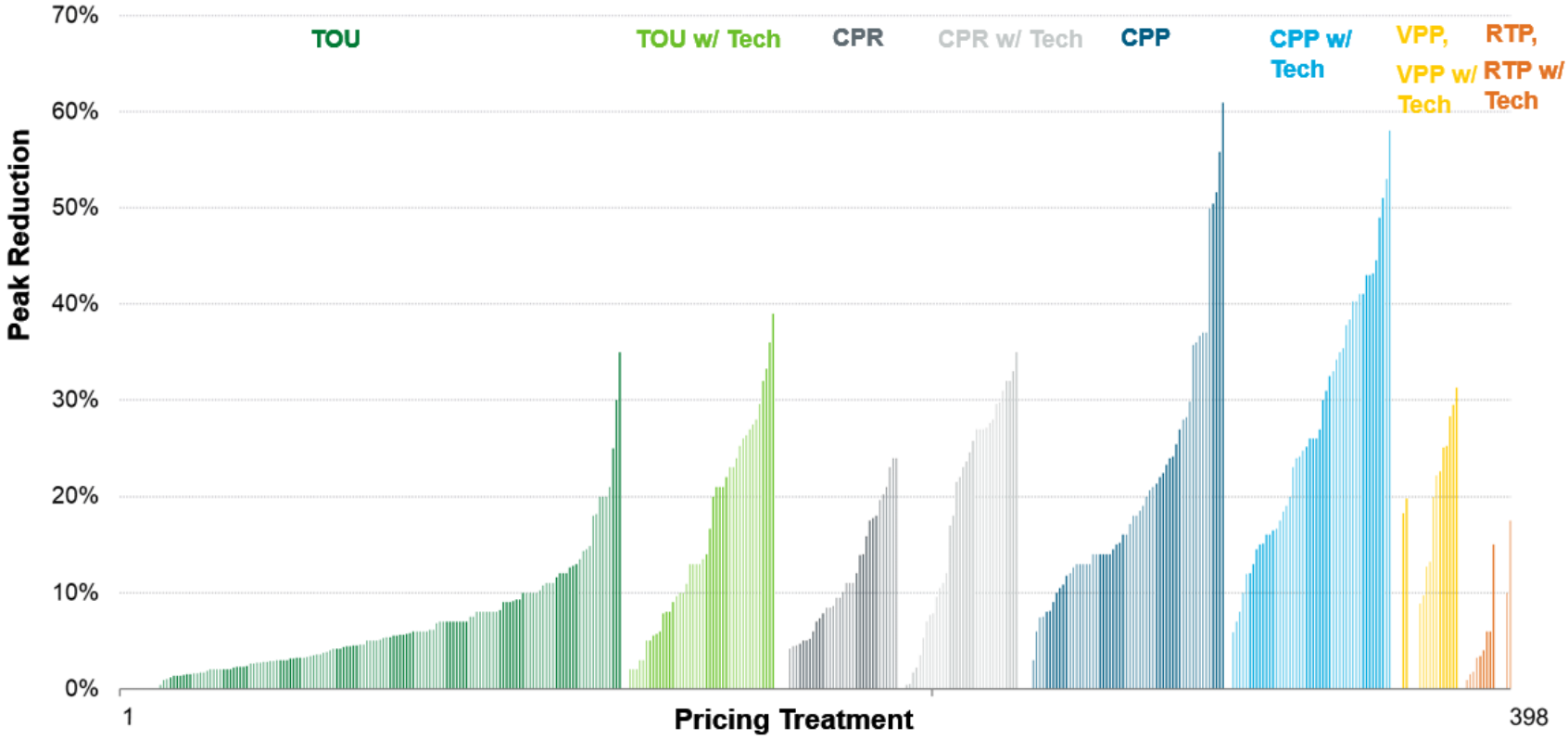
Residential TOU Rates



- Very common across the country
- Opt-in enrollment tends to be very low (~1% - 5%), with some notable exceptions (e.g., Arizona)
- Shown to be highly effective for shifting EV load, with 80 – 90% of charging occurring outside of peak hours
- Customers may be unwilling to enroll whole home load on TOU rate and may be more open to enrolling only EV load (separately metered) if metering costs are not substantial

TOU rates from other jurisdictions

- Research from the Brattle Group indicates that customers respond to time-varying rates.



Source: Results from 79 pricing pilots and programs and 398 individual treatments in the Arcturus database.

Sergici, S. Brattle. Time-of-Use Rate Design and Roll-out: Learnings from Other Jurisdictions. Maine PUC Docket No. 2024-00231. October 8, 2024.

Residential Whole-Home and EV-Only TOU Examples

Utility	Rate	Season	On/Off Peak Price Ratio	Whole-house or EV only
SDGE (CA)	TOU-5	Summer Winter	6.3:1 4.2:1	Whole-house
	EV TOU	Summer Winter	2.8:1 1.9:1	EV Only
Con Edison (NY)	TOU Residential	Summer Winter	14.2:1 5.2:1	Either
SCE (CA)	TOU Residential	Summer Winter	3.7:1 2:1	EV Only
PSEG (NY, Long Island)	Short Peak - TOU Residential	Summer Winter Shoulder	1.7:1 1.5:1 1.3:1	Whole-house
	Early Peak -TOU Residential	Summer Winter Shoulder	1.6:1 1.5:1 1.3:1	Whole-house
Hawaiian Electric Company	TOU-RI, separately metered EV	No seasonal variation	2.2:1	EV only
Pepco (MD)	Plug-in Vehicle (PIV) TOU	Summer Winter	1.4:1 1.8:1	EV Only
	Residential Plug-in Vehicle (R-PIV) TOU	Summer Winter	1.3:1 2.1:1	Whole-house
Northern States Power – Xcel Energy (MN)	Electric Vehicle Home Service	Summer Winter	8.2:1 7.2:1	EV Only
	Res. EV Svc (EV Accelerate at Home)	Summer Winter	3.2:1 2.6:1	EV Only
PacifiCorp (OR)	Separately Metered EV Service	Summer Winter	1.4:1 1.2:1	EV Only
Salt River Project (AZ)	Residential EV Price Plan	Summer Winter Shoulder	3.8:1 1.6:1 3.3:1	Whole-house

Brief History of TOU in the District

Residential TOU in the District of Columbia

- **1982:** The DC PSC determined that TOU rates were appropriate for the 800 largest residential customers (FC 759, Phase II, Order No. 7713). TOU billing began in 1986.
- **1988:** The Commission authorized a pilot program for Pepco to examine the cost-effectiveness of extending TOU rates to residential customers whose usage exceeded 2,500 kWh. Those customers were transitioned to TOU in 1990.
- **1990:** The PSC approved extending TOU to all customers whose usage exceeds 2,500 kWh in two or more summer months. Pepco began issuing parallel bills to these customers.
- **1995:** Full transition to TOU for customers with usage >2,500 kWh in the summer was delayed due to concerns of gradualism, followed by mergers and restructuring.

Residential TOU in the District of Columbia

- The TOU rate, R-TM, initially had summer/winter seasons and three periods (peak, intermediate, and off-peak.)

1995 Schedule R-TM – Generation, Transmission, & Distribution

Summer	$/kWh	Winter	$/kWh
On-Peak	0.23	On-Peak	0.09
Intermediate	0.09	Intermediate	0.09
Off-Peak	0.07	Off-Peak	0.08
Summer peak to off-peak price	3.05:1	Winter peak to off-peak price	1.15:1

- The rate continued after restructuring but was limited to the 800 largest residential customers. The on/off peak price ratio also declined.

2009 Schedule R-TM – SOS Portion

Summer	$/kWh	Winter	$/kWh
On-Peak	0.13	On-Peak	0.12
Intermediate	0.11	Intermediate	0.11
Off-Peak	0.10	Off-Peak	0.10
Summer peak to off-peak price	1.37:1	Winter peak to off-peak price	1.14:1

Residential TOU in the District of Columbia

- In 2020, the Residential Plug-In EV Rate (R-PIV) went into effect with on-peak hours of non-holiday weekdays 12 pm – 8 pm (8 hours).

2020 Schedule R-PIV – Generation, Transmission, & Distribution (>400 kWh)

Schedule R-PIV - Generation, Transmission, Distribution

Summer	$/kWh	Winter	$/kWh
On-Peak	0.13	On-Peak	0.14
Off-Peak	0.06	Off-Peak	0.06
Summer peak to off-peak price	2.14:1	Winter peak to off-peak price	2.27:1

- In March 2024, the Multi-Dwelling Unit EV Rate (MDU-PIV) went into effect with on-peak hours of non-holiday weekdays 6 am – 8 pm (14 hours).

2024 Schedule MDU-PIV – Generation, Transmission, & Distribution

Summer	$/kWh	Winter	$/kWh
On-Peak	0.27	On-Peak	0.27
Intermediate		Intermediate	
Off-Peak	0.16	Off-Peak	0.16
Summer peak to off-peak	1.76:1	Winter peak to off-peak price	1.72:1

Overarching Design Considerations

Considerations for TOU design

PRINCIPLE	APPLICATION
Simplicity, understandability, public acceptability, and feasibility	• Avoid too many rate periods/prices • On-peak to off-peak price ratios sufficient to attract customers • Avoid substantial adverse bill impacts • Rate options: not all rates work for all customers • Iteration: evaluate and update over time
Revenue sufficiency	• Revenue neutral for each class
Stability	• Consider future costs to avoid frequent changes to rate structure
Fairness	• Revenue neutral for each class, based on allocated class revenue requirements • Ensure customers have the tools to respond
Efficiency	• Rates based on underlying marginal costs • Avoid unnecessary grid investments by reducing peak demand
Cost-effective*	• Cost of implementation < Benefits
Aligned with District's energy policy goals*	• Affordability • Account for emissions rates in determining structure • Encourage beneficial electrification where possible

Recommendations: Customer acceptance

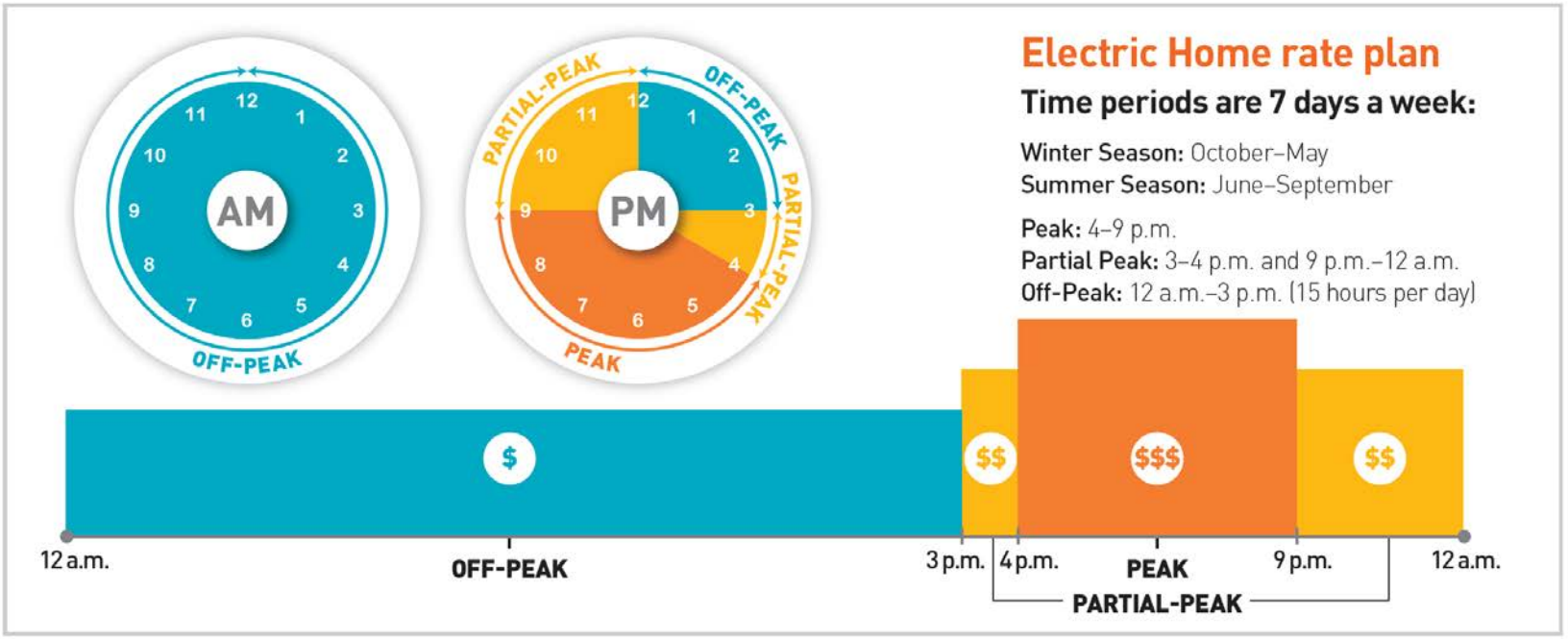
- **Opt-in vs opt-out:**
  - Begin with opt-in rates, followed by a deliberate transition to opt-out coupled with customer protections at an appropriate point.

- **Price differentials**
  - On-peak to off-peak price differentials of between 2:1 and 3:1 for opt-in rates are common and tend to provide adequate bill savings while avoiding high risk of bill increases
  - Potential to save money relative to standard rate should be obvious. This may involve modifying the standard rate to encourage more enrollment in the TOU rate.
  - Opt-out rates should begin with milder price differentials.

- **Load shifting ability**
  - On-peak window should be short enough to allow customers to effectively shift load .
  - Ability to shift load varies depending on technology access (EVs, programmable thermostats and appliances).

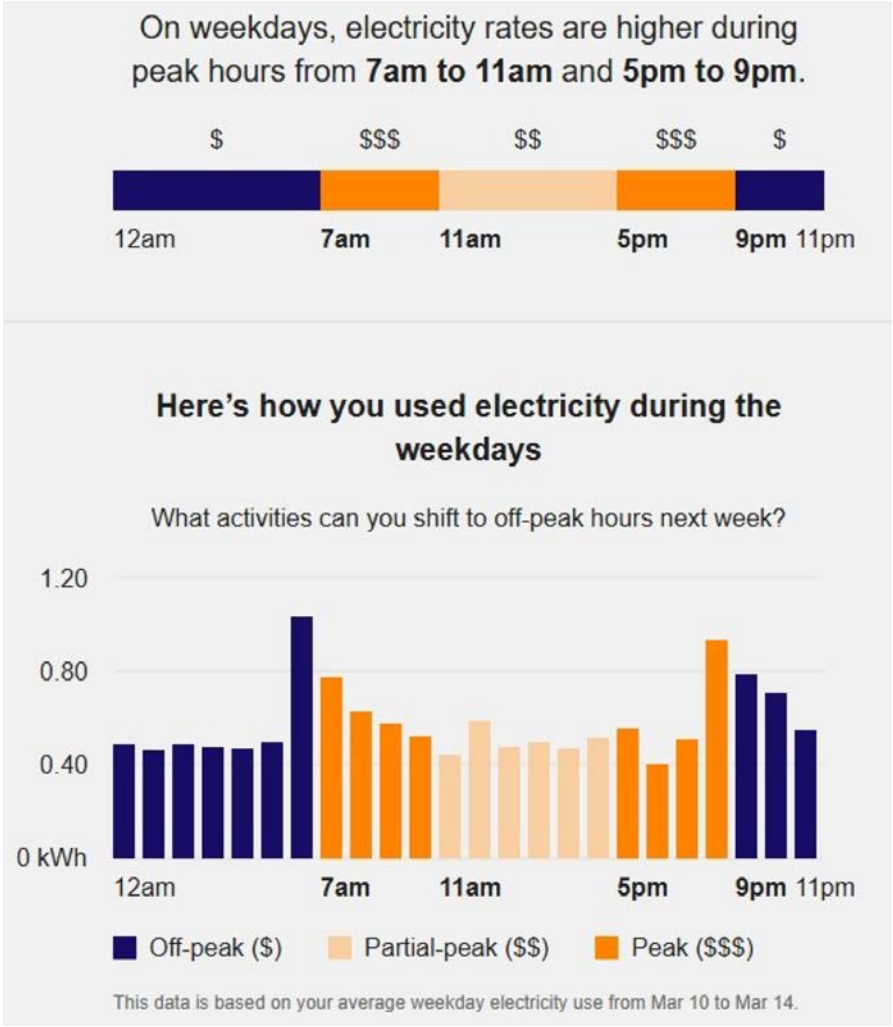
Recommendations (cont.)

- **Customer Understanding**
  - Keep rates simple (3 or fewer periods).
  - Provide educational & marketing resources in multiple formats (online, print, etc.).
  - Consider best practices from other jurisdictions.
    - Examples: Personalized marketing and online calculators
    - Easy to understand graphics



Recommendations (cont.)

- Provide continual feedback and useful information



Source: BGE, 2025

Recommendations: Efficiency

- **Consider marginal costs when designing rates**
- **Distribution marginal costs**
  - Estimated annual benefit of reducing demand-related distribution costs = $209/kW
    - Distribution demand-related marginal costs reported by Pepco in FC1176 are $209/kW for non-coincident area peak demand *(Source: FC1176, Bonikowski Exhibit PEPCO (E)-17, p. 7 of 10.)*
- **Energy market costs (locational marginal prices)**
  - Summer late afternoon/evening costs are more than double other summer hours
- **Capacity costs**
  - Current PJM PEPCO zone capacity costs = $270/MW-day (= $98/kW-yr)
  - Occur primarily during summer afternoons between 4 pm – 5 pm
- **Recommendation:** Rates should be designed with both distribution and wholesale market marginal costs and peak timing in mind to avoid perverse impacts.

Average LMPs 2023-2024 ($/MWh)	
Summer 3 pm - 7 pm	$69
Summer 7 pm - 3 pm	$32
Winter 3 pm - 7 pm	$42
Winter 7 pm - 3 pm	$33

Timing of Marginal Costs

Energy supply: Day-Ahead PEPCO Zone Locational Marginal Costs (2023-2024)

	12:00 AM	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
January	39	38	37	37	39	44	57	68	56	49	47	44	42	40	39	39	45	59	56	54	51	47	43	39
February	24	24	23	24	26	30	41	46	36	32	31	29	27	26	24	25	28	36	41	37	35	32	28	25
March	21	21	20	21	23	28	42	47	34	29	28	27	26	24	23	22	23	26	30	37	35	30	26	23
April	24	24	22	22	23	28	38	37	32	30	30	30	30	30	30	32	34	37	39	47	50	38	31	27
May	25	23	20	19	20	25	29	30	31	33	34	37	40	42	45	49	55	61	59	56	53	43	34	28
June	21	19	17	15	16	18	20	21	23	26	29	33	38	42	47	52	60	64	58	51	43	39	31	25
July	27	23	20	18	17	20	23	25	28	34	39	49	58	67	77	93	109	115	96	75	58	50	38	32
August	24	22	18	17	17	20	23	23	24	28	31	38	44	50	56	65	75	79	69	56	46	39	32	27
September	23	21	18	17	18	22	29	29	27	30	32	35	39	43	46	51	59	69	62	55	45	37	31	26
October	27	26	23	23	25	31	48	62	43	34	33	33	35	36	38	41	49	67	81	72	49	42	37	30
November	27	26	25	26	28	34	51	56	40	33	32	31	30	29	29	31	40	57	48	42	39	35	32	28
December	31	30	29	30	32	36	54	65	43	35	34	32	31	30	29	31	39	53	46	44	42	39	35	31

Highest LMPs tend to be from **3–8 pm** in the summer

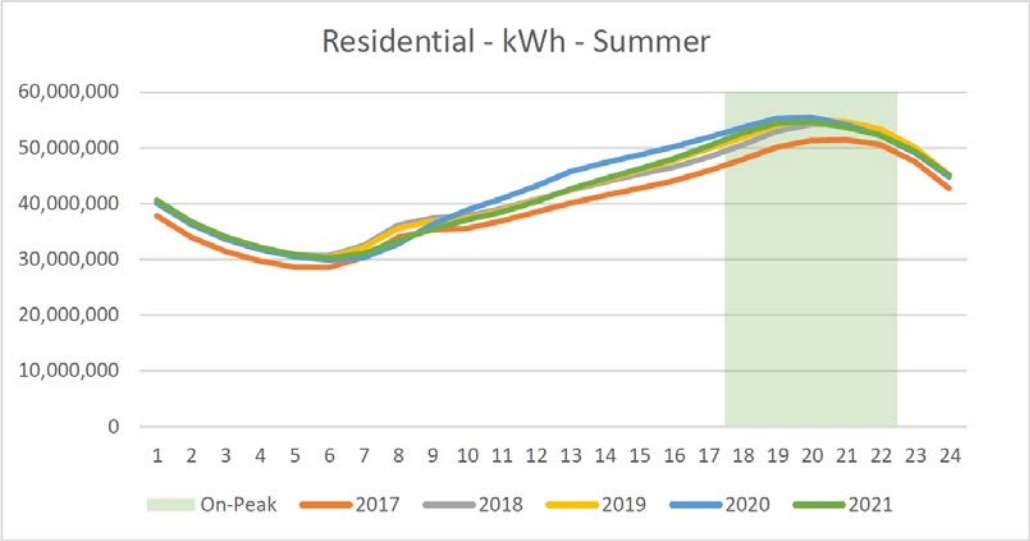
Capacity costs: PJM 5 CP hours (2018-2024)

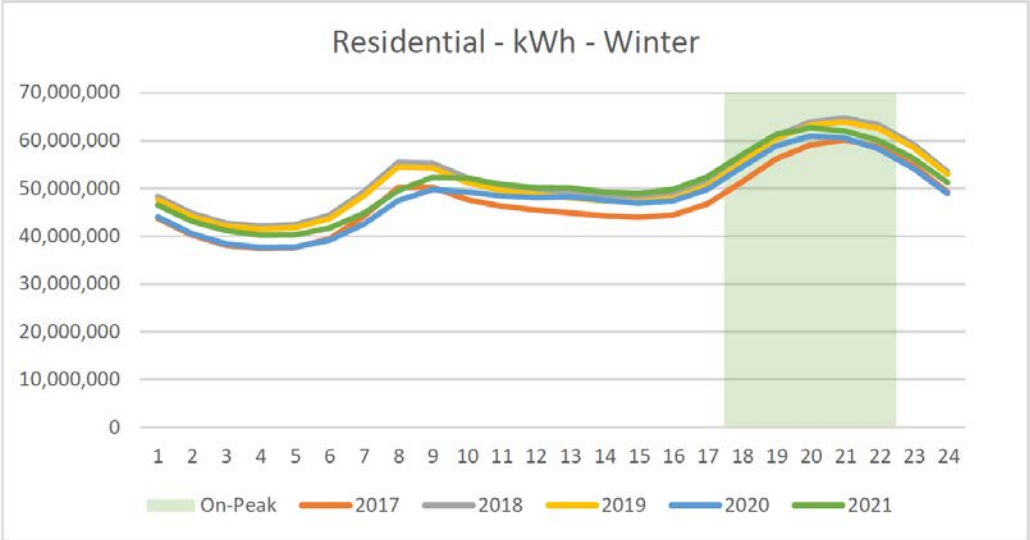
	12:00 AM	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
January	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
February	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
June	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	1	0	0	0	0	0	0
July	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	4	11	2	0	0	0	0	0
August	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	3	5	0	0	0	0	0	0
September	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	0	0	0	0	0	0	0
October	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
November	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
December	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PJM peak hours tend to occur from **4–6 pm** in the summer

(COVID resulted in a single 2 pm peak)

Pepco Residential Load





Distribution peak period appears to be more concentrated around **6–9 pm**

(Would be helpful to review updated data for 2022-2024)

Recommendation: Consider benefits vs. costs

How can TOU help utilize grid more efficiently?

- **Avoid/defer distribution capital:**
  - Pepco's capacity expansion budget: $186 million for 2023-2027 (*Source: 2024 ACR*)
  - Pepco's load forecast indicates 16 Pepco substations will experience increases in peak demand >1 MW by 2033 (*Source: 2024 ACR*)
- **Reduce PJM market clearing prices:**
  - Eventually resulting in lower SOS full requirements bids and savings for non-SOS customers (e.g., by lowering PJM's assignment of capacity obligations for the Pepco zone as a whole).
- **Experience from Maryland:**
  - BGE: 0.30 kW/customer during BGE peak (9.3%)
  - Pepco: 0.34 kW/customer during Pepco peak (13.6%)
- **Recommendation:** Calculate benefits of reducing peak load ($/kW) and compare to cost of administering TOU rates

Substation #	Projected Increase in Demand 2024-2033 (MVA)
230	78.1
13	50.8
21	34.2
133	30.7
136	30.5
7	19.3
190	18.5
12	16.3
10	15
18	14.6
223	13.9
38	9.8
168	8
129	4.7
77	1.7
27	1.2

Straw Proposal – Residential TOU

Straw Proposal

1. Begin with offering a menu of opt-in rates

- At least one whole-home TOU rate
- One EV-only rate (separately metered, ideally using vehicle telematics or smart charger to reduce customer costs)
- Consider more advanced rate offerings after implementing simpler TOU rates (e.g., critical peak pricing)

2. Support customer adoption and utilization

- The people part of the program is as important as the rate design itself. Customers need to have the tools to make informed decisions about what rates are best for their households, and take advantage of them.
- Identify implementation steps and partnerships (e.g. with DOEE and the DCSEU) to spur enrollment and support customers in understanding and utilizing different rates.

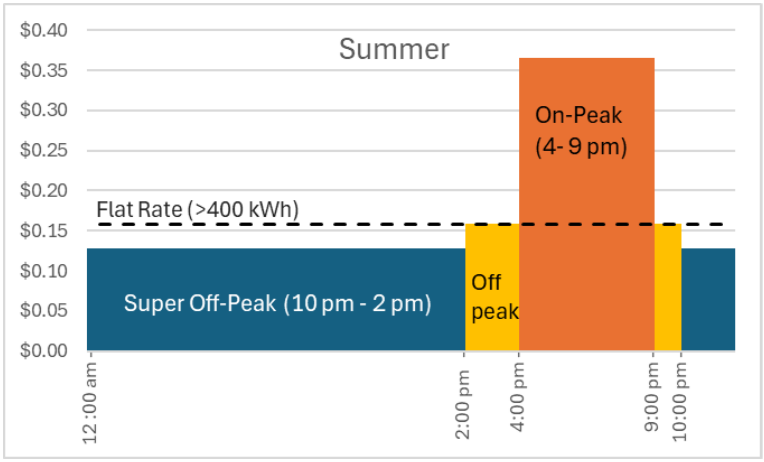
Straw Proposal

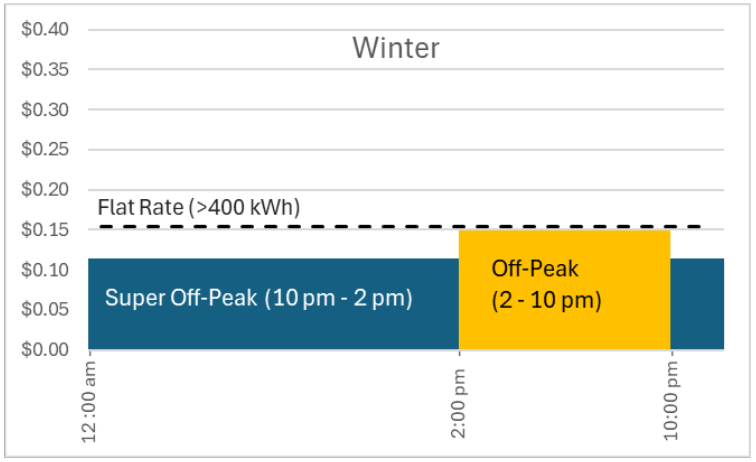
3. Evaluate effectiveness of TOU rates, customer acceptance, and impacts on vulnerable customers, and develop a plan to transition to an opt-out rate on an appropriate time frame (e.g., 5-7 years).

- Assess load shifting through evaluations
- Analyze enrollment rates and conduct surveys to understand customer concerns
- Evaluate potential impacts of an opt-out TOU rate on low-income customers and other vulnerable groups and develop a plan for mitigating impacts (e.g. automatic enrollments into utility discount programs)
- Identify a timeline to consider a transition to opt-out rates, based on evaluation of DC rates and lessons learned from other utilities and states that have transitioned to opt-out rates.

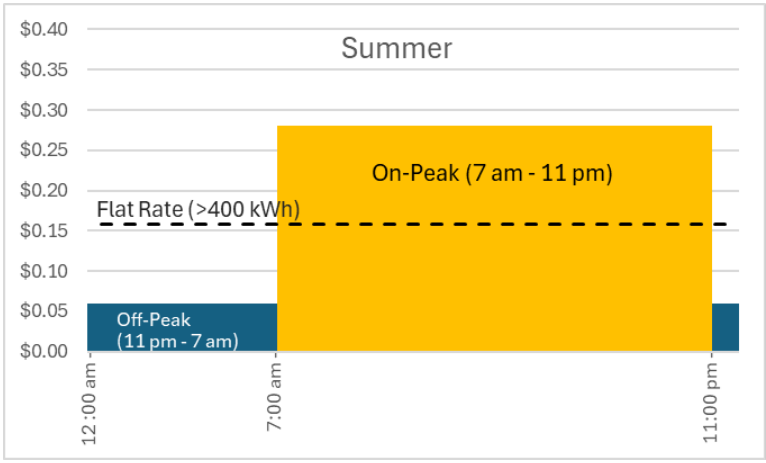
Residential Straw Proposal – G, T, & D rates

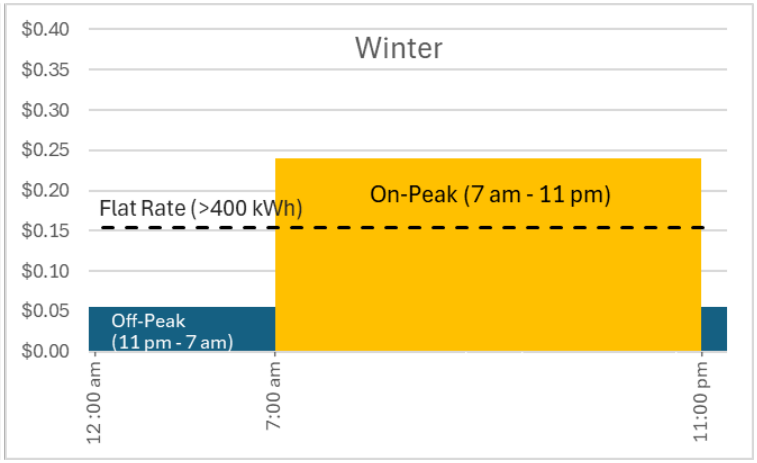
R-TOU (open to all residential customers)





EV-TOU (separately-metered EV rate)





R-TOU Straw Proposal

Season	Period	Hours	R <400 kWh	R >400 kWh	R-TOU Straw Proposal All kWh	Price relative to R (>400 kWh) $/kWh
Summer (June – Oct)	On-Peak	4 - 9 pm	0.13	0.16	0.37	0.21
	Off-Peak	2-4 pm, 9-10 pm	0.13	0.16	0.16	(0.00)
	Super-Off-Peak	10 pm - 2 pm	0.13	0.16	0.13	(0.03)
Winter (Nov-May)	Off-Peak	2-10 pm	0.14	0.15	0.15	(0.00)
	Super-Off-Peak	10 pm - 2 pm	0.14	0.15	0.11	(0.04)

- 5-hour on-peak window
- Bundled on-peak to off-peak price ratio: ~3:1 during summer
  - Approximately 3:1 price ratio for supply and distribution components
- Strong seasonal differentiation improves economics of building electrification (i.e., heat pumps).
- Super off-peak price provides EV charging savings of ~$11/month (relative to standard R rate).
- Rates same or lower than marginal R rate in all periods except summer peak to improve attractiveness to customers.

R-TOU Straw Proposal

- Rate by Component

Season	Period	Distribution	Transmission	Supply	Total
Summer	**On-Peak**	0.0550	0.0900	0.2200	**0.3650**
	Off-Peak	0.0350	0.0140	0.1100	**0.1590**
	Super Off-Peak	0.0244	0.0130	0.0900	**0.1274**
Winter	**Off-Peak**	0.0350	0.0140	0.1000	**0.1490**
	Super Off-Peak	0.0244	0.0130	0.0770	**0.1144**

Residential EV-TOU Straw Proposal

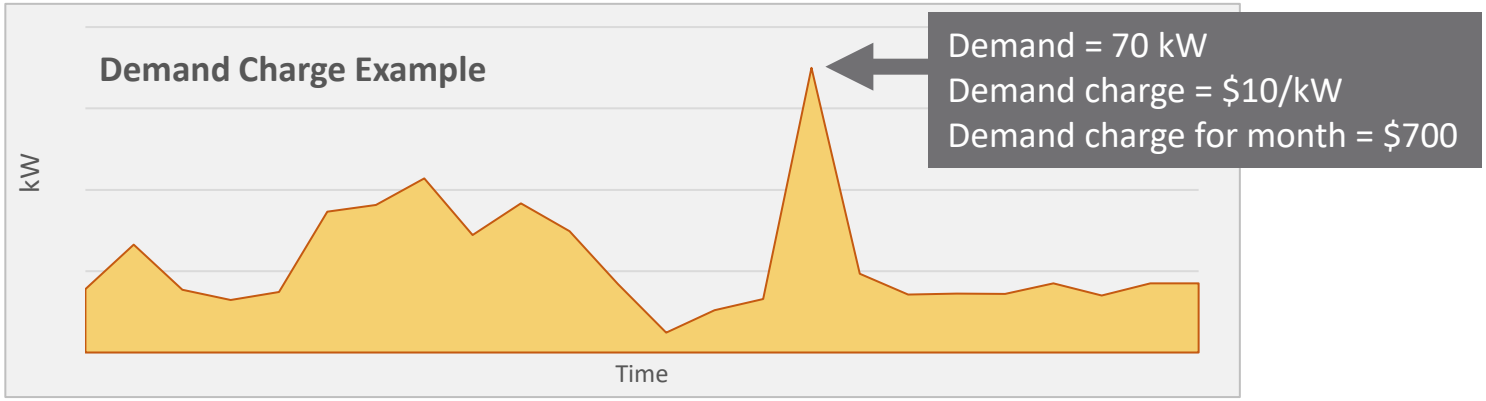
Season	Period	Hours	R <400 kWh	R >400 kWh	EV-TOU Straw Proposal All EV Charging kWh	Price relative to R (>400 kWh) $/kWh
Summer (June – Oct)	On-Peak	7 am - 11 pm	0.13	0.16	0.28	0.12
	Off-Peak	11 pm - 7 am	0.13	0.16	0.06	(0.10)
Winter (Nov-May)	On-Peak	7 am - 11 pm	0.14	0.15	0.24	0.09
	Off-Peak	11 pm - 7 am	0.14	0.15	0.06	(0.10)

- 16-hour on-peak window in order to provide lower off-peak prices
- Off-peak price provides EV charging savings of ~$30/month (relative to standard R rate).

Commercial TOU Rates: Initial Considerations

Demand charges and District energy policy goals

- **Demand charges** tend to pose the biggest barriers for commercial EV customers (including public DCFC and fleets) when EV adoption is low



Demand charges are difficult for customers with low load factors, where the quantity of electricity consumed (kWh) is low but the demand (kW) is high.

Option 1: Convert Demand Charges to Volumetric

- Higher volumetric rates in exchange for reduced or eliminated demand charges
- May be permanent or temporary

Example: NV Energy offers a temporary conversion of demand charges to time-of-use volumetric rates. The demand charge is gradually phased back in from 2020 – 2029.

Benefits:

- Reduces bills for low load-factor customers, helping to support fleet adoption and DCFC construction

Challenges:

- Requires well-designed volumetric rate to provide efficient price signals. (Flat volumetric rates do not accurately reflect costs on the grid.)
- If temporary, must be in place long enough to support business case for DCFC and fleets, or will not accomplish goals

Option 2: Low Load-Factor Rates

- Caps demand charges for customers with low load factors
- May or may not increase volumetric rate proportionately

Example: For DCFC customers, Arizona Public Service limits the monthly billed demand relative to the Customer's monthly kWh usage. Monthly billing demands are limited to a kW no higher than what would result with a load factor of 25% through 2025. The load factor limit ratchets down from 2025 – 2031.

Benefits:

- Reduces bills for low load-factor customers

Challenges:

- May not be fully cost-based, depending on design
- If temporary, must be in place long enough to support business case for DCFC and fleets, or will not accomplish goals

Thank you!

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Appendix

Bonbright's Principles of Public Utility Rates

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.
6. Fairness of the specific rates in the appointment of total costs of service among the different customers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency… 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, etc.)

James Bonbright, Principles of Public Utility Rates, 1961, page 291

How to allocate distribution costs for season/TOU?

- A few options:
  1. Allocate costs according to season in which most substations peak (e.g., if 95% of substations peak in summer, allocate 95% of demand-based costs to summer).
  2. Allocate costs according to the load in each hour.
  3. Allocate costs according to "load squared" method. This method allocates costs to each hour based on the square of the load in that hour. Higher load hours receive a much larger share of costs due to squaring the load value.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%
February	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%
March	0.2%	0.2%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.2%	0.2%	0.2%
April	0.2%	0.2%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.4%	0.3%	0.3%	0.3%	0.2%
May	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.4%	0.4%	0.5%	0.6%	0.7%	0.7%	0.7%	0.7%	0.6%	0.6%	0.5%	0.4%	0.3%
June	0.4%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.5%	0.6%	0.7%	0.8%	0.9%	1.0%	1.0%	1.0%	0.9%	0.8%	0.7%	0.7%	0.6%	0.5%
July	0.4%	0.4%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.5%	0.6%	0.7%	0.8%	0.9%	1.0%	1.1%	1.1%	1.1%	1.0%	0.9%	0.8%	0.8%	0.6%	0.5%
August	0.4%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.5%	0.6%	0.7%	0.8%	0.8%	0.9%	0.9%	0.9%	0.8%	0.7%	0.7%	0.6%	0.5%	0.4%
September	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.4%	0.4%	0.5%	0.6%	0.6%	0.7%	0.7%	0.7%	0.6%	0.6%	0.5%	0.5%	0.4%	0.3%
October	0.2%	0.2%	0.2%	0.1%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%
November	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%
December	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.2%