Nova Scotia Utility and Review Board

IN THE MATTER OF *The Public Utilities Act*, R.S.N.S. 1989, c.380, as amended

Time-Varying Pricing Project Submission

Nova Scotia Power

June 30, 2020

NON-CONFIDENTIAL

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APPENDICES

1.0 EXECUTIVE SUMMARY

This submission marks a milestone in the development of Nova Scotia Power Inc.'s (NS Power, Company) use of tariffs as a tool for providing customers with a choice of time differentiated pricing signals to support their desire to reduce their electricity costs. The implementation of Advanced Meter Infrastructure (AMI) in combination with Time-Varying Pricing (TVP) will allow customers to track and manage their consumption across the day and throughout the year to better align their electricity usage with their financial and lifestyle objectives.

This submission presents NS Power's initial findings and recommendations concerning the introduction of TVP with respect to:

- The initial TVP proposed tariff offerings; a Critical Peak Pricing Tariff and a Time-of-Use Tariff.
- Updated peak and off-peak periods to focus customer demand reduction on the periods of greatest monthly and daily load peaks and highest marginal cost for the NS Power system.
- Recommended time of use and critical peak pricing applicable to the Residential, Small General and General Demand classes.
- Calculation of the forecast demand reduction effect of these tariffs and the customer bill and revenue effects of the programs across various pricing ratios.
- Recommendations concerning customer engagement and initial pilot design if this is determined desirable by stakeholders and the Nova Scotia Utility and Review Board (Board, NSUARB).

This work has been developed in collaboration with the Brattle Group (Brattle), who are industry leaders in time-varying pricing. The information presented within this submission provides a complete record of our engagement with Brattle and support for the conclusions and recommendations presented. Key findings include:

- Savings in customer demand as enabled by AMI in combination with TVP are expected to meet or exceed the forecast savings presented in the AMI capital application.
- Individual customer and class effects remain difficult to forecast until NS Power has the interval data provided by AMI and more experience with TVP operation in Nova Scotia. However, moving forward at this time and continuing to target TVP offerings in 2021/2022 remains appropriate as it will allow the Company to develop the required systems to support these efforts and advance customers' experience with these tools when the AMI data becomes widely available.
- While enabling long-term savings in the form of reduced generation capacity and fuel cost, TVP programs are likely to create near-term revenue shortfalls to the Company as customers shift load from peak to off-peak periods. The magnitude of this will ultimately be determined by the TVP programs implemented and level of customer take-up. However, a plan to address the revenue shortfall will be required in order to align recovery of this revenue reduction with the future capacity savings realized.

In recognition of the large breadth of this undertaking and scope of options associated with TVP tariff offerings and prices, the Company is not presenting its findings for approval of the Board at this time but rather proposes to use the work completed to date as a foundation for engaging stakeholders on the development of its final proposal to the Board in the Fall of 2020. This 2-part regulatory approach will:

- Allow the parties to work collaboratively to refine NS Power's initial work and amend the Company's proposal as required.
- Promote development of consensus on matters through active, transparent and informal stakeholder engagement.
- Place the Company and customers in a position to have tariffs approved by the Board ready to be implemented when the AMI roll-out is expected to be complete in mid-2021.

- Employ a stakeholder engagement model which has proven effective in the past when undertaking major initiatives like TVP. The best example of this is the Cost of Service customer engagement and regulatory proceeding of 2013.[1]

NS Power is requesting that the Board open a proceeding that includes a collaborative process to finalize development of a TVP proposal that would then be put forward for Board approval. NS Power is proposing a two part approach:

- Part 1: It is proposed that Part 1 of the proceeding is a consultative process focused on stakeholder engagement beginning with the examination, review and refinement with stakeholders of the materials presented herein and concluding with the filing of an application by the Company with the Board for approval of the proposed TVP tariffs. Part 1 would include technical conferences and data exchanges among the parties. The Board's opening of the proceeding would provide a vehicle for informing interested parties of the application and establishing a formal record of parties to have received related materials. NS Power requests the Board provide a timeline in which Part 1 is to be completed, including the filing of an application for approval of TVP tariffs and that the conclusion of this timeline be no later than November 30, 2020, so as to allow sufficient time for the Board to make a determination on the application and TVP tariffs to be implanted prior to the completion of the AMI roll-out currently scheduled for mid-2021.

- Part 2: Once initiated by the filing of an application for approval of TVP tariffs, Part 2 of the proceeding would then consist of the regulatory process required for the Board to hear the application and make a determination.

[1] M05473, NS Power 2013 Cost of Service Study

2.0 INTRODUCTION

In the NSUARB Decision dated June 11, 2018 in the Matter of an Application by NS Power for approval of Capital Work Order Cl 47124, Advanced Metering Infrastructure Project (M08349), the Board provided:

> [107] The Board also acknowledges the concerns raised by the AEC regarding possible impact of time varying pricing programs on low income consumers, and recognizes that development of such programs and tariffs would be based on voluntary customer enrolment.
>
> [108] In its June Compliance Filing, NSPI is directed to advise the date by which it will file the time varying pricing tariffs.
>
> [222] The following directives are also included in the Decision:
> ….
> (ii) NSPI is directed to take into account the concerns of low income consumers, as well as small business customers, as it implements AMI and to consider the comments of the AEC and SBA regarding time-of-day usage tariffs and prepayment plans as they impact on such customers;

Following the Company's submission of its Compliance Filing dated June 26, 2018, the Board provided:

> 3. NS Power is directed to file its time varying pricing tariffs with the Board on June 30, 2020, …
>
> 7. NS Power is directed to take into account the concerns of low income consumers, as well as small business customers, as it implements AMI and to consider the comments of the Affordable Energy Coalition and Small Business Advocate regarding time-of-day usage tariffs and prepayment plans as they impact on such customers.

To support the Company's development of these TVP Tariffs, NS Power has engaged Brattle. The Brattle engagement is being led by Dr. Ahmad Faruqui and Dr. Sanem Sergici.

Dr. Faruqui is a Principal with the Brattle Group and leads the firm's retail energy practice. He has four decades of experiencing in time-varying pricing, gained by working for utilities and regulatory bodies in Australia, Canada, Hong Kong, Malaysia, New Zealand, Saudi Arabia, and the United States. He has testified on the topic several times and presented on the subject on all six continents.

Dr. Sergici is a Principal with The Brattle Group, specializing in program design, evaluation, and big data analytics in the areas of energy efficiency, demand response, smart grid and innovative pricing. She assists her clients in their strategic and regulatory questions related to retail rate design and grid modernization investments. 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 many states/provinces and regions including District of Columbia, Connecticut, Florida, Illinois, Maryland, Michigan, Ontario, California, and New Zealand.

Copies of the resumes of Dr. Faruqui and Dr. Sergici are attached as **Appendices 9** and **10,** respectively.

Brattle has provided insight on industry best practices in this area and supported the Company's development of its preliminary proposals for the TVP program. Brattle also prepared forecasts of peak reductions and revenue reductions that would be achieved from alternative TVP offerings at varying peak/off-peak pricing differentials using its proprietary database, Arcturus, which contains the results of nearly 400 tests of TVPs from around the world. Recognizing the early stage of TVP development in which NS Power and its customers are operating and the potential of TVP to serve as an important long-term resource planning tool, Brattle also provided guidance as to best practices for broad introduction of these new and innovative rate structures.

Within this submission NS Power is presenting its initial findings and recommendations with respect to TVP program development. The Company is not presenting TVP Tariffs for the Board's approval at this time, but rather requests the Board initiate a regulatory proceeding within which the Company's preliminary work can be discussed with stakeholders and final tariff proposals developed over the next few months in collaboration with customers and their representatives.

The purpose of approaching the TVP project in this manner is to develop a shared understanding among NS Power and stakeholders as to concerns, issues, and assumptions underlying TVP Tariff development, including, as directed by the Board, those concerns of low income and small business customers. This approach allows for TVP Tariffs to be in place at the completion of the AMI roll-out currently forecast for mid-year 2021, while also benefiting from the information gained by the continued progression of the Integrated Resource Planning (IRP) and other regulatory processes and undertakings. If successful, it is NS Power's hope that this proposed process would lead to development of consensus among parties on many of the issues associated with the introduction of TVP. For broad, complex undertakings, such as TVP tariff development, this collaborative model has proven effective in the past, an example of which is the 2013 Cost of Service proceeding.

In the remainder of this submission, the Company provides:

- Background materials with respect to TVP program development and activity in other jurisdictions and TVP best-practices
- Preliminary recommendations for TVP program offerings, including:
    - Peak/off-peak pricing periods
    - Residential, Small General and General Demand TVP offerings
    - Pricing alternatives with forecast demand and revenue effects
- NS Power and Brattle qualitative and quantitative analyses underlying the Company's preliminary TVP tariff recommendations
- A review of regulatory and operational matters associated with the development and introduction of TVP in Nova Scotia
- An update on the AMI rollout
- A proposed collaborative stakeholder engagement process intended to support development of consensus among parties on many of the complex issues associated with

the broad introduction of TVP and to refine NS Power's preliminary recommendations as required in advance of submitting the Company's application for approval of TVP Tariffs to the Board in the Fall of 2020.

3.0 TIME-VARYING PRICING DEVELOPMENT TO DATE

Work undertaken with Brattle to date is summarized below and expanded upon in the eight Brattle presentations included as Appendices 1 to 8:

1. Review and assessment of TVP options (Appendix 1)
2. Development of jurisdictional scan (Appendix 2)
3. Compilation of TVP Design Best Practices and Recommendations for NS Power (Appendix 3)
4. Development of peak/off-peak pricing periods (Appendix 4)
5. Development of pricing options across classes (Appendix 5)
6. Forecast of customer and system load impacts (Appendix 6)
7. Forecast of customer bill and NS Power revenue impacts (Appendix 7)
8. Compilation of information on TVP pilot design best practices (Appendix 8)

The Brattle presentations included in the above referenced appendices describe these activities in detail and present initial findings. A summary of the work in each area, with reference to the applicable Brattle research and Brattle/NS Power analyses and findings, follows.

3.1 Review and Assessment of TVP Options

Established TVP options are examined in **Appendix 1** and summarized by Brattle in **Figure 1.**

Figure 1. Time-Varying Rate Options

Rate	Definition
1- Time-of-Use *(TOU)*	The day is divided into peak and off-peak time periods. Prices are higher during the peak period hours to reflect the higher cost of supplying energy during that period
2- Critical Peak Pricing *(CPP)*	Customers pay higher prices during critical events when system costs are highest or when the power grid is severely stressed
3- Peak Time Rebates *(PTR)*	Customers are paid for load reductions on critical days, estimated relative to a forecast of what the customer would have otherwise consumed (their "baseline")
4- Variable Peak Pricing *(VPP)*	During alternative peak days, customers pay a rate that varies by day to reflect dynamic variations in the cost of electricity
5- Real-Time Pricing *(RTP)*	Customers pay prices that vary by the hour to reflect the actual cost of electricity
6- Two-part Real-Time Pricing *(2-part RTP)*	Customer's current rate applies to a baseline level of consumption. A second, marginal cost based, price applies to deviations from the baseline consumption
7- Three-part Rates *(3-part Rates)*	In addition to volumetric energy charge and fixed charge, customers are also charged based on peak demand, typically measured over a span of 15, 30, or 60 minutes
8- Fixed Bill with Incentives	Customers pay a fixed monthly bill accompanied with tools for lowering the bill (such as incentives for lowering peak usage)

NS Power currently provides an optional Domestic Service Time of Day Tariff (comparable to a TOU Tariff) and Real-Time Pricing in the large customer sector. Several years ago, a Two-part Real-Time Pricing Tariff was in effect for the Company's largest customers.

A Critical Peak Pricing Tariff was included in the Company's AMI capital application economic analysis as an illustration of the potential value of AMI when paired with a TVP Tariff as a tool for reducing utility peak load and reducing utility investment in generation capacity. The CPP program was forecast to produce a capacity savings of 26 MW. It was understood that, should the Board approve the AMI capital application, a more detailed assessment of TVP alternatives would be undertaken prior to developing a TVP tariff application for Board approval.

Pros and cons of each TVP Tariff form are presented by Brattle in **Appendix 1**.

3.2 Jurisdictional Scan

Brattle's jurisdictional scan (**Appendix 2**) shows that, to date, smart meters have been deployed to more than 60 percent of U.S. homes and are expected to be in use by more the 80 percent of North American homes by 2024. However, the widespread subscription to TVP rates remains in its early stages as only 4 percent of U.S. residential customers are on TVP Tariffs.

For jurisdictions that do offer TVP Tariffs, there is common use of both voluntary (i.e. opt-in) and default offerings wherein customers may opt-out. Mandatory TVP offerings are employed but these are less common, with only one of the jurisdictions considered by Brattle having mandatory TVP.

As directed by the Board, the Company is approaching the initial offerings as voluntary, on an opt-in basis. However, as part of this customer engagement, it is expected that the implications of mandatory and opt-out programs will be examined.

Of the TVP programs/jurisdictions considered by Brattle, Time-of-Use Rates (comparable to NS Power's Optional Domestic Service Time of Day Tariff) are the most common offerings,[2] while CPP rates are found to be the most effective in delivering peak reduction.[3] As would be expected,

[2] Appendix 3, page 10.
[3] Appendix 3, page 8.

Brattle's work demonstrates that across TVP programs, the greater the discount being offered in off-peak periods relative to the peak period, the greater the incentive to shift load from peak to off-peak periods, and therefore the greater the effect on peak demand. When paired with enabling technologies (e.g. smart thermostats), the effect of TVP on capacity reduction is amplified.

It is understood there will be differences across jurisdictions in TVP take-up and impact. In some cases, these differences may result from whether the utility is winter-peaking or summer-peaking. Information and analysis on jurisdictions with a winter peak, like Nova Scotia, is provided in the Brattle jurisdictional scan.[4]

A summary of lessons learned from TVP rate deployments in other jurisdictions and implications for the NS Power implementation is presented in the Brattle jurisdictional scan across the five categories listed below with key findings:

1. Designing the Rates

   To avoid cost transfer and to match system savings with costs a Lost Revenue Adjustment Mechanism is likely to be required.

2. Marketing the Rates

   Though the Company has experience with TVP in Residential and Large Industrial customer classes, limited general awareness across the customer population means the implementation of TVP tariffs requires deliberate and extensive customer engagement.

3. Inclusion of Enabling Technologies

   Recent/pending programs including the Intelligent Feeder Program[5] and Smart Grid Nova Scotia Project (M09519), and work with EfficiencyOne (E1) with respect to Demand

[4] Appendix 2, page 7, and individual details on Hydro-Quebec and BC Hydro.

[5] M07981, NS Power Cl# 49787 Intelligent Feeder Project, approved August 21, 2017

Response,[6] provide opportunities to build on this experience and establish processes for future equipment/TVP pairings.

4. Inclusion of Behavioral Messaging

The Company remains in the early days of AMI roll-out and time is required to develop analytics and processes regarding engagement with customers employing the AMI data such that customers can have confidence they will realize savings from the TVP programs offered.

5. Transitioning to New Rates

NS Power requires a TVP Strategy that aligns TVP development and implementation with NS Power AMI deployment, industry developments and continued generation transformation for the benefit of all customers. The Strategy should be underpinned by Company resource planning developments (i.e. IRP) and emerging opportunities/initiatives (e.g. Smart Grid Nova Scotia project).

Key to the strategy will be disciplined and transparent customer engagement processes that utilize the AMI data.

3.3 TVP Design Best Practices and Recommendations for NS Power

As a foundation for assessing alternative TVP rate designs, Brattle provides a list of Rate Design Principles set out in **Figure 2** which are based on the well-established Bonbright principles, as described in **Appendix 3.**

[6] M09096, 2020-2022 DSM Resource Plan

Figure 2. Principles of Rate Design

(Bonbright Principles, adapted based on "NYREV Order Adopting A Ratemaking and Utility Revenue Model Policy Framework," May 2016.)

Principles	Objective
1. Cost causation	• Rates should reflect cost causation, including embedded costs, long-run marginal and future costs, and the fixed cost nature of delivering electricity
2. Encourage efficient outcomes	• Rates should encourage economically efficient and market-enabled decision-making, for both efficient use of the grid by customers and new investments
3. Fair Value	• Customers and utility should both be paid the fair value for the grid services they provide
4. Customer Orientation	• Rates should aspire for simplicity while providing customer choices
5. Stability	• Customer bills should be relatively stable
6. Access	• Electricity should remain affordable and accessible for vulnerable sub populations
7. Gradualism	• Rate changes should be implemented in a manner which would not cause any large bill impacts
8. Economic Sustainability	• Rate design should reflect a long-term approach to price signals, remain neutral to any particular technology or business cycle and avoid cross-subsidies and prevent abuse/gaming/arbitrage

The analysis in the Brattle presentation reflects the collaborative work of Brattle and NS Power. Based on the analysis and information to date, it is recommended by Brattle that NS Power offer a Critical Peak Pricing Tariff and Time-of-Use Tariff, initially as opt-in programs. If implemented, it is considered appropriate to examine whether these should become default programs once the tariffs have been in operation for three years and customer acceptance has been demonstrated.[7]

Support for proposing these two tariff constructs includes the following:

- A CPP Tariff provides the greatest, most immediate effect on system demand when it is most needed and resultant realization of benefits for all customers.

[7] Appendix 3, page 6.

- TOU Tariffs are the most common TVP offerings in the industry providing a strong foundation for NS Power's program implementation and a base-level of load shifting on most days. The Company has direct experience with a TOU offering in its current Residential TOD Tariff.

In addition to proposing the Company proceed to develop CPP and TOU offerings, Brattle provides comments on matters that should be considered as part of the TVP program rate design. These include the following as applicable to CPP and TOU programs.

Critical Peak Pricing

- The design of the rates should balance system efficiency and cost savings with customer experience. If the rate design poses undue hardship on participating customers, it is unlikely to be adopted and the targeted cost savings are unlikely to be achieved.
- Number of event days, frequency of critical peak events, and duration of critical peak events should all be carefully considered (no more than 8-12 days should be called in a given season).
- CPP is typically designed to reflect long-run marginal cost of capacity to meet system peak and short-run marginal cost of energy during critical peak hours.
- CPP should be sufficiently high to give customers meaningful incentives for load shifting.
- Customers should be given sufficient notice to plan their load shifting activities. However, the shorter the lead time, the greater the value of demand reductions from a utility planning perspective.

Time of Use

- Seasonal differences in load shapes and price differentials should be considered in designing the rates.
- Simplicity of the design and customer education and outreach are key to increasing the uptake of the rate among customers.

- Behavioural messaging, smart thermostats and bill impact tools can accompany the rates to enhance comprehension and responsiveness.
- Keep the peak periods short.
- Refrain from multiple periods, especially split mid-peak periods unless there is a good basis.
- Undertake billing analysis to determine the effects on customers with various usage patterns and the amounts by which their bills will go up or down prior to any load shifting.
- In determining the peak period, consider the change in load shape that might take place as solar penetration ramps up over time.
- Target a peak/off-peak ratio that gives customers a material opportunity to save by reducing peak loads and/or shifting loads to the off-peak period. A lower ratio will not lead to sizable savings for customers and will not motivate load shifting.[8]

3.4 Development of Pricing Periods

A key initial step in the development of TVP Tariffs is the determination of pricing seasons and peak windows. This is discussed in **Appendix 4.** Information compiled is summarized below:

<u>Pricing Seasons</u>

To determine pricing seasons, Brattle examined NS Power weekday system load curves across months for 2018-2019 as summarized in **Figure 3** and **Figure 4** below. Figure 3 suggests NS Power's load profile exhibits three distinct seasonal patterns.

[8] Appendix 3, pages 10-12.

Figure 3. Weekday System Load Profile by Month

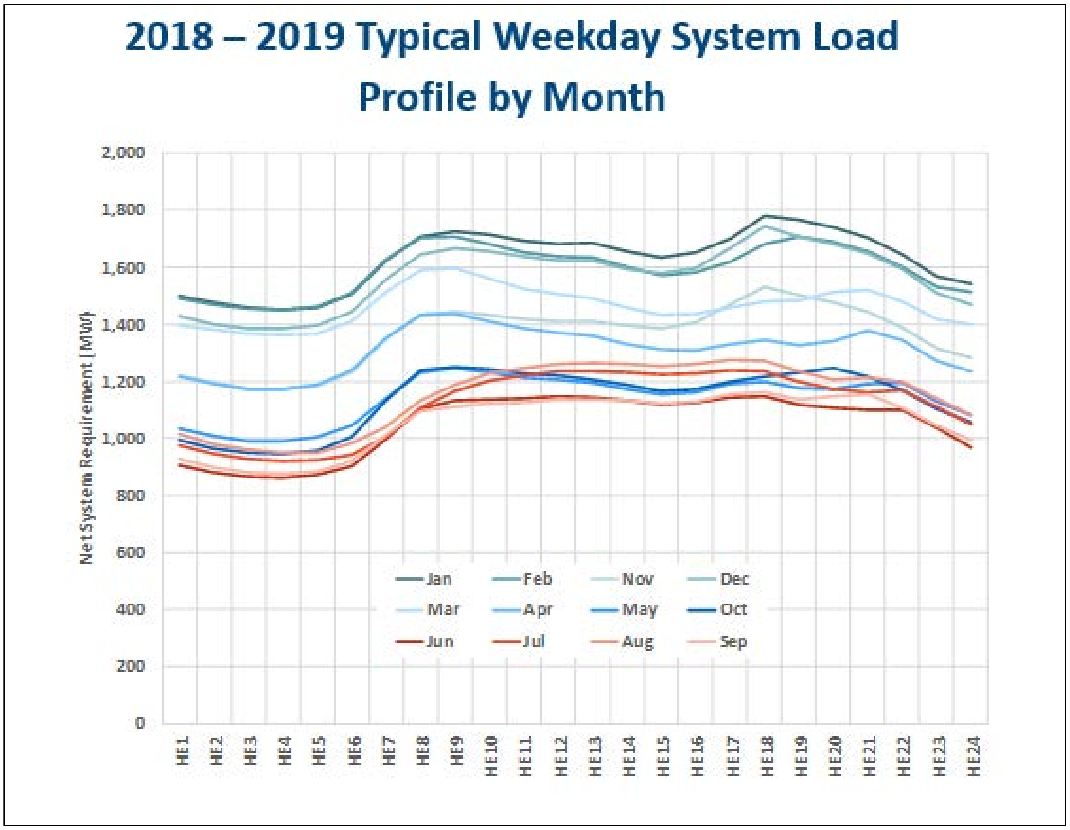


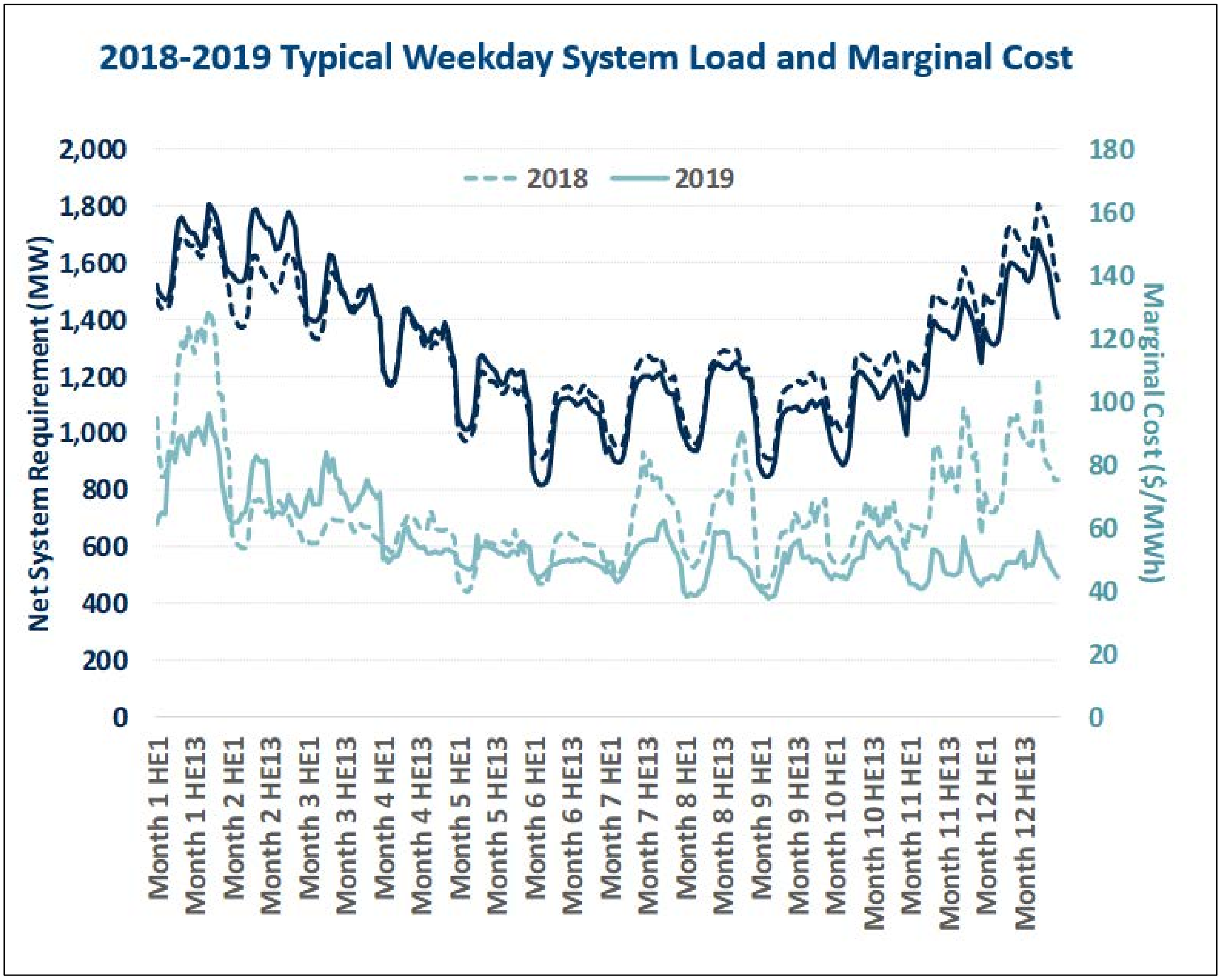
Figure 4. Seasonal Patterns in Load

Winter	January, February, November, and December feature bimodal peaks (morning and evening), with a more pronounced evening peak.
Summer	June through September features mostly flat load during the daytime.
Spring & Fall	March, April, May, and October feature lower load with bimodal peaks, with a more pronounced morning peak.

Peak Windows

To determine the daily peak/off-peak windows, Brattle examined NS Power's hourly net system requirement and marginal cost profiles for 2018 and 2019 using Cluster Analysis, which is reproduced in **Figure 5** below.[9]

Figure 5. Weekday System Load and Marginal Cost



The process for developing the recommended peak periods is described in **Appendix 4**.

[9]Cluster Analysis is a statistical technique that seeks to determine the natural groupings (or clusters) of observations, such that observations in the same group are as similar to each other as possible.

Based on the Brattle analysis, the periods set out in **Figure 6** have been selected for consideration by stakeholders.

Figure 6. Seasonal Peak Periods

Winter Peak Period	January, February, November, December Hour Ending (HE) 8 – HE 11; HE 17 – HE 20 (Appendix 4 page 8)
Summer Peak Period	June, July, August, September HE 13 – HE 19 (Appendix 4 page 9)
Spring & Fall Peak Period	March, April, May, October HE 8 – HE 12 (Appendix 4 page 10)

These TVP periods are similar to those currently employed for the Residential TOD program. Significant differences are as follows:

- There are three TVP seasonal periods (Winter, Summer, and Spring & Fall) versus the two seasons applied in the current Residential TOD Tariff (Winter and non-Winter).
- There is an additional winter peak period month (November).
- The winter morning and evening peak periods are narrowed and there is no shoulder period proposed.
- The Summer and Spring & Fall season peaks are narrowed significantly; the Summer focused on the evening peak and the Spring & Fall TVP season focused on the morning peak.

3.5 Development of Peak/Off-peak Pricing Alternatives

The Company developed pricing scenarios for a range of TVP CPP and TOU options across the Residential, Commercial, and Industrial sectors. The process and results are presented in **Appendix 5**. As summarized in **Figure 7**,TVP options examined included CPP with Standard

Offer Rate (SOR)[10] and in combination with various TOU offerings as well as separate TOU offerings with differing peak periods.

Figure 7. TVP Options

	# TOU Seasons	CPP?	Winter Definition	Description
SOR	0	No	*n/a*	Constant flat volumetric charge in all hours of the year
CPP/SOR	0	Yes	*n/a*	Constant flat volumetric charge in all hours of the year, except for CPP hours
TOU #1	3	No	Nov – Feb	Peak and off-peak periods in each of the three seasons; Separate flat rates in Spring & Fall and Summer, with seasonal differentiation
TOU #2	3	No	Nov – Feb	Peak and off-peak periods in each of the three seasons; Single flat rate in Spring & Fall and Summer, with no seasonal differentiation
TOU #3A	1	No	Nov – Feb	Peak and off-peak periods in Winter only; Flat rate in Spring & Fall and Summer
TOU #3B	1	No	Nov – Mar	Peak and off-peak periods in Winter only; Flat rate in Spring & Fall and Summer
TOU #4A	1	No	Nov – Feb	Peak period in Winter only; Flat rate in all remaining hours, except for CPP hours
TOU/CPP #4A	1	Yes	Nov – Feb	Peak period in Winter only; Flat rate in all remaining hours, except for CPP hours
TOU #4B	1	No	Nov – Mar	Peak period in Winter only; Flat rate in all remaining hours
TOU/CPP #4B	1	Yes	Nov – Mar	Peak period in Winter only; Flat rate in all remaining hours, except for CPP hours

For the above options, prices have been developed for non-time of day residential, commercial and industrial classes. For the initial assessment of TVP potential, the focus of the work has been on the non-time of day Residential, Small General and General Demand classes. In 2019, collectively these classes accounted for approximately 68 percent of load, 75 percent of Company revenue and 95 percent of customers.

The steps used in this pricing development are summarized in **Figure 8** below.

[10] Standard Offer Rate refers to current electricity pricing.

Figure 8. Pricing Development Process

Step 1:	Identify overall structure of TVP rates guided by the Brattle Cluster Analysis
Step 2:	Align peak to off-peak energy charge ratios under the TOU tariffs rates with the ratios of peak to off-peak marginal class costs in each season
Step 3:	Develop TOU rates on the basis of revenue neutrality in cost recovery (i.e. revenue under current rates equal to TVP prices without load shifting)
Step 4:	Develop CPP and TOU/CPP combined tariffs on the basis of revenue neutrality in cost recovery

The rationale and specific approach applied to develop the initial pricing across the various TVP options is expanded upon in the Brattle presentation (**Appendix 5**). While providing a foundation for the Company's initial proposals and the TVP stakeholder engagement, the work to date has reinforced the importance of sharing and vetting this information with stakeholders in order to provide an opportunity for stakeholder input on the tariffs and associated pricing in advance of NS Power finalizing its recommendations and making an application to the Board for approval of TVP tariffs.

Figure 9 below presents the preliminary rates for the proposed TVP Tariffs for the Residential Class. For TOU 3B, TOU 4B, and TOU/CPP 4B, as shown in Figure 7, Winter corresponds to November to March. Spring & Fall includes April, May, and October. The Summer period includes June to September. For all other rates, Winter corresponds to November- February, Spring & Fall to March - May and October, and Summer to June – September. The examination of the differing price periods provides an opportunity to consider the demand response effects of the TVP prices across different periods.

Figure 9. Preliminary Rates Developed for TVP Options

	Customer ($/month)	On-Peak Rate (c/kWh)			Flat or Off-Peak Rate (c/kWh)			CPP Rate (c/kWh)
		Winter	Spring & Fall	Summer	Winter	Spring & Fall	Summer	
SOR	*$10.83*				*16.215*	*16.215*	*16.215*	
CPP/SOR	$10.83				11.682	11.682	11.682	231.271
TOU #1	$10.83	46.928	28.894	29.524	11.712	8.403	7.915	
TOU #2	$10.83	46.951	29.350	29.350	11.717	8.169	8.169	
TOU #3A	$10.83	62.629			12.052	8.539	8.539	
TOU #3B	$10.83	52.245			11.799	8.088	8.088	
TOU #4A	$10.83	64.131			9.676	9.676	9.676	
TOU/CPP #4A	$10.83	50.673			6.933	6.933	6.933	231.271
TOU #4B	$10.83	53.822			9.610	9.610	9.610	
TOU/CPP #4B	$10.83	41.220			6.933	6.933	6.933	231.271

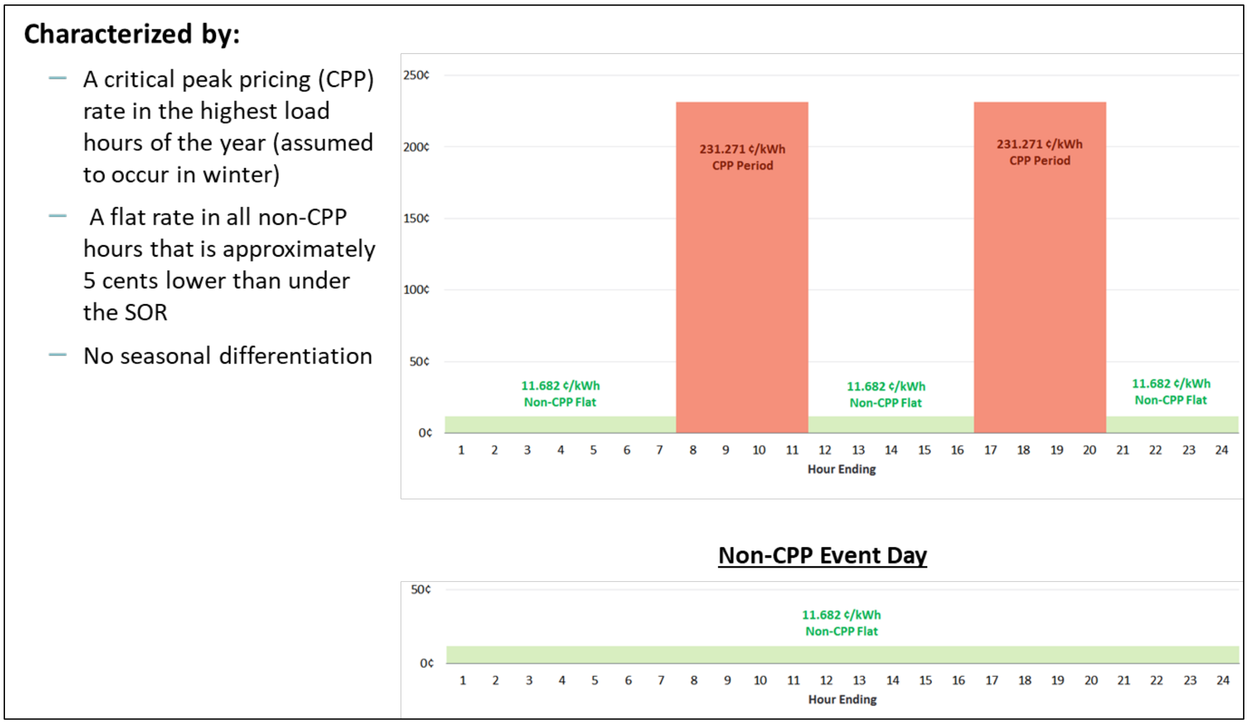
As discussed previously, because the peak/off-peak differential is a key driver of customer response, it is helpful to consider the peak/off-peak ratios of the TVP prices developed. For the initial suite of prices developed the ratios are summarized in **Figure 10** below. In general, a ratio above 3:1 is expected to achieve a moderate level of load shifting, with more meaningful load shifting delivered by ratios in excess of 4:1.

Figure 10. Preliminary Peak/Off-Peak ratios for TVP Options

	Peak/Off-Peak Ratio			
	Winter	Spring & Fall	Summer	CPP
SOR/CPP				17.7
TOU #1	3.7	3.1	3.3	
TOU #2	3.7	3.2	3.2	
TOU #3A	4.7			
TOU #3B	4.0			
TOU #4A	5.9			
TOU/CPP #4A	6.2			27.7
TOU #4B	5.0			
TOU/CPP #4B	5.1			27.7

For the options including CPP, the ratios are large in reflection of the relatively few CPP hours to which the CPP prices apply. The potential magnitude of this variance is illustrated in **Figure 11** below.

Figure 11. CPP Event Pricing Example

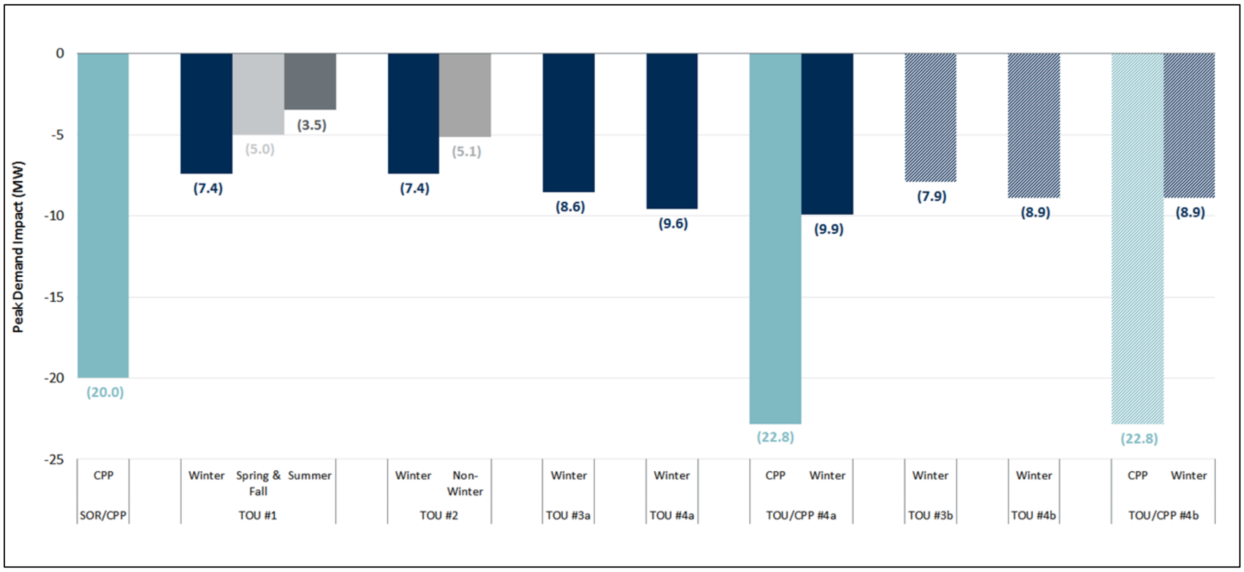


3.6 Forecast of Capacity Effects of Programs and Pricing Alternatives

Brattle has applied the TVP option pricing foundation developed by NS Power to forecast customer and system impacts of the various TVP options at varying peak/off-peak ratios. The Brattle methodology is described in **Appendix 6**. Given that the Brattle database, Arcturus, is predominantly composed of pricing experiments that were carried out by summer-peaking utilities, Brattle modelling applied a 50 percent derating factor to the forecast demand responsiveness to allow for anticipated lower customer response for NS Power as a winter peaking utility.

The forecast peak demand reduction for Residential customers across the TVP options examined is summarized in **Figure 12.**

Figure 12. Peak Demand Reduction Forecast for TVP Options



As expected, Figure 12 indicates that programs with CPP are forecast to have the greatest effect on system demand by a large margin. Under the peak/off-peak differential examined, the forecast peak demand savings in the residential class for the CPP/SOR program is 20 MW. Similar results are forecast for the Small General and General Demand classes across the various TVP programs though, consistent with the programs being applied to smaller customer classes, the demand reductions are less.

To understand the potential variability in demand response according to differing peak/off-peak pricing differentials Brattle modelled sensitivities. For CPP, variants tested ranged from 50 cents/kWh to $2.00/kWh. For TOU peak/off-peak ratios tested ranged from 2:1 – 4:1.

The results are projected in **Figure 13** and **Figure 14** below for the Residential, Small General and General Demand classes individually and combined. The graphs indicate that even under the most conservative peak/off-peak differentials the combined peak reductions for CPP and TOU programs are forecast to deliver almost 20 MW of peak reduction.

Figure 13. CPP Peak Demand Reduction, Residential, Small General and General Demand classes[11]

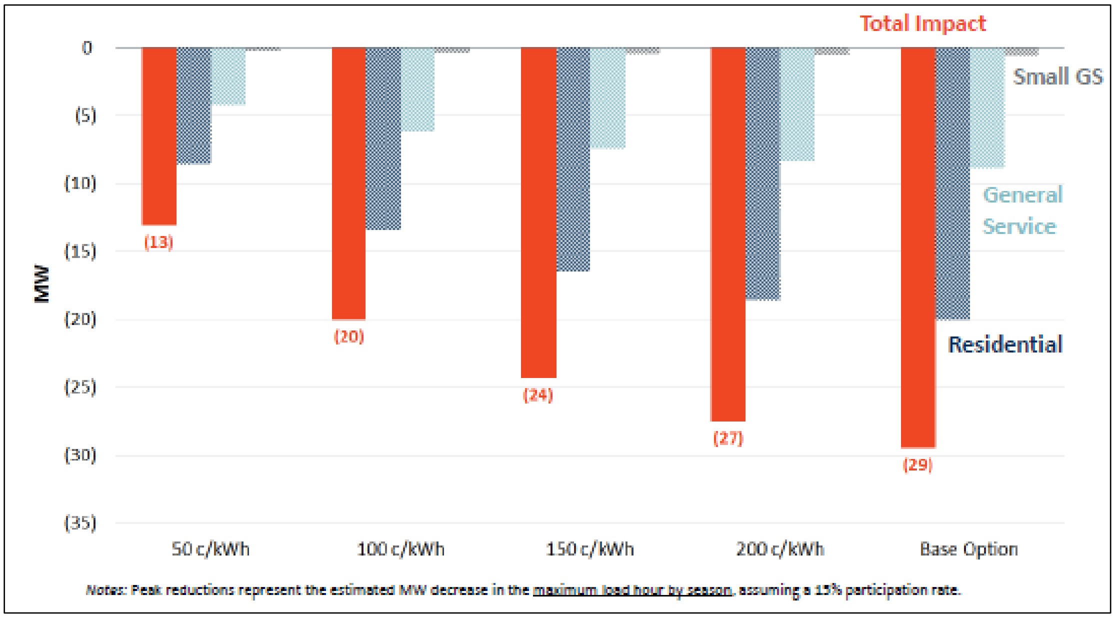
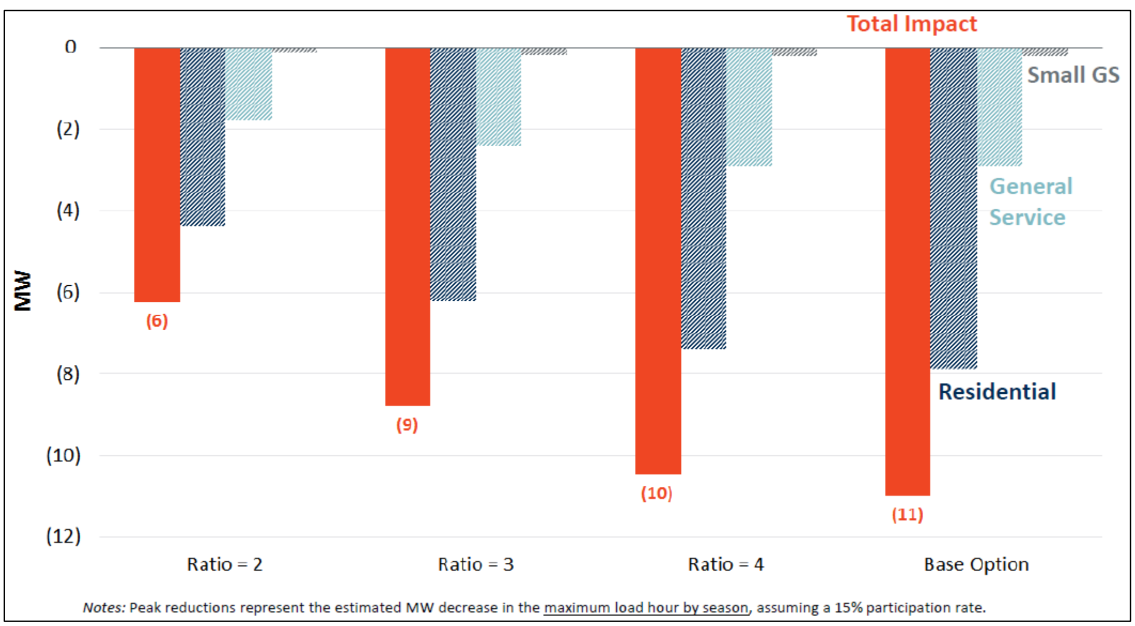


Figure 14. TOU Peak Demand Reduction, Residential, Small General and General Demand classes[12]



[11] Appendix 6, page 22
[12] Appendix 6, page 21

Conclusions from Brattle's analysis include the following:

- Even at relatively modest peak/off-peak differentials ($1.00/kWh critical peak price) and applied only to the Residential, Small General and General Demand classes, CPP rates are forecast to deliver 20 MW of capacity reduction. This is almost 80 percent of the capacity saving included in the Company's AMI capital application. Extended to additional classes or with higher peak/off-peak differentials the capacity reductions may exceed that included in the AMI capital application.

- The TOU scenario, while providing a more modest contribution to peak reduction, remains significant. Again, only for the three classes noted above, even at a ratio of only 2:1, the impact is forecast to reduce a peak reduction of 6 MW.

- The CPP rate (with a $1.00/kWh peak price) and the TOU rate at a 2:1 ratio, for only these three customer classes, are forecast to produce a capacity reduction equal to that included in the Company's AMI capital application.

- The CPP program for these classes at a peak price of $1.50/kWh and a TOU program ratio of 3:1 is forecast to deliver a peak reduction of 33 MW. However, this recommendation suggests a revenue shortfall of approximately $10 million could be created by these programs. This is significant and likely would require a revenue deferral and recovery mechanism to address.

3.7 Customer Bill and Company Revenue Impacts

Brattle has completed an analysis of the effect of the programs on customers and the resultant effect on Company revenues (**Appendix 7**). This analysis employs NS Power load research data and reflects experience in other jurisdictions.

3.7.1 Customer Impacts

<u>Residential Customers with Electric Heat</u>

For CPP/SOR for Residential customers with electric heat the analysis concludes:

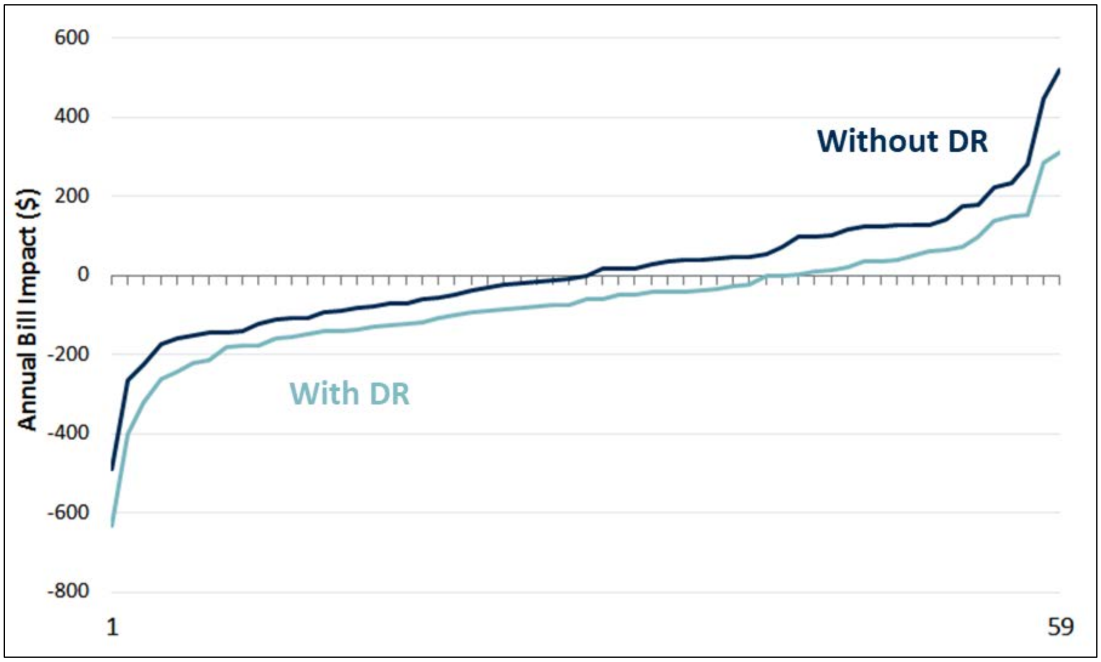
- Under the CPP/SOR rate, 51% of electric heat customers experience *lower bills* without changing their consumption pattern, compared to 69% who experience lower bills when they respond to price signals by changing their consumption pattern.

    - Without changes to consumption patterns, there is an average annual bill reduction of $105 and an average annual bill increase of $128, with an overall average bill impact of $9.

    - With changes to consumption patterns, there is an average bill reduction of $133 and an average bill increase of $85, with an overall average bill impact of -$67.

The distribution of these increases and decreases across the class sample for customers with electric heat is illustrated in **Figure 15** below.

Figure 15. Bill Effects (Residential with Electric Heat), for 59 customers modeled[13]



Residential Customers without Electric Heat

For CPP/SOR for Residential customers without electric heat the analysis concludes:

- Under the CPP/SOR rate, 71% of non-electric heat customers experience lower bills without changes to consumption patterns compared to 80% who change consumption patterns in response to price signals.

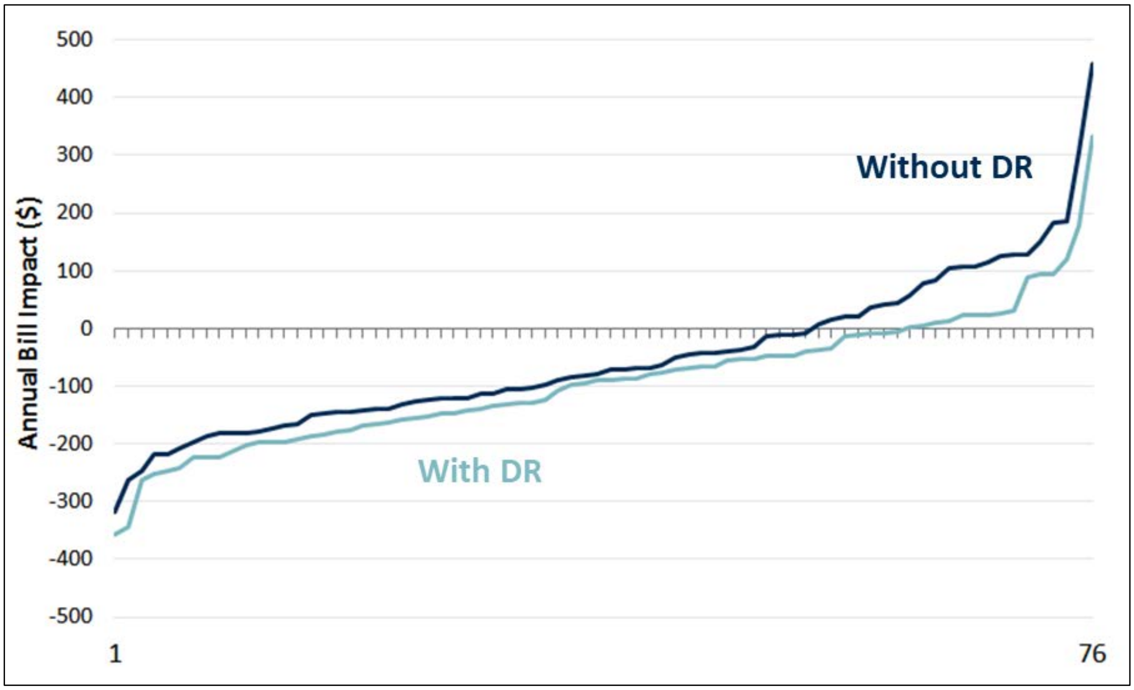
    - Without changes to consumption patterns, there is an average bill reduction of $120 and an average bill increase of $114, with an overall average bill impact of -$52.

    - With changes to consumption patterns, there is an average bill reduction of $132 and an average bill increase of $71, with an overall average bill impact of -$92.

[13] Appendix 7, page 9.

The distribution of these increases and decreases across the class sample for customers without electric heat is illustrated in **Figure 16**.

Figure 16. Bill Effects (Residential Non-electric Heat), for 76 customers modeled[14]



This analysis is repeated for the TVP options examined with the results presented in **Appendix 7.** The distribution of these increases and decreases across the class sample for customers without electric heat for the CPP/SOR program is shown in Appendix 7, along with the same information for the other TVP options examined.

3.7.2 Revenue Impacts

The Brattle analysis also develops a forecast of the lost revenue at varying pricing levels. Because the TVP prices are developed as revenue neutral, as the customers respond to the price signal and shift load, which is the intent of the program, customers will reduce their bills. However to the extent the customer savings exceed the resultant near-term cost reductions of the utility (primarily

[14] Appendix 7, page 10.

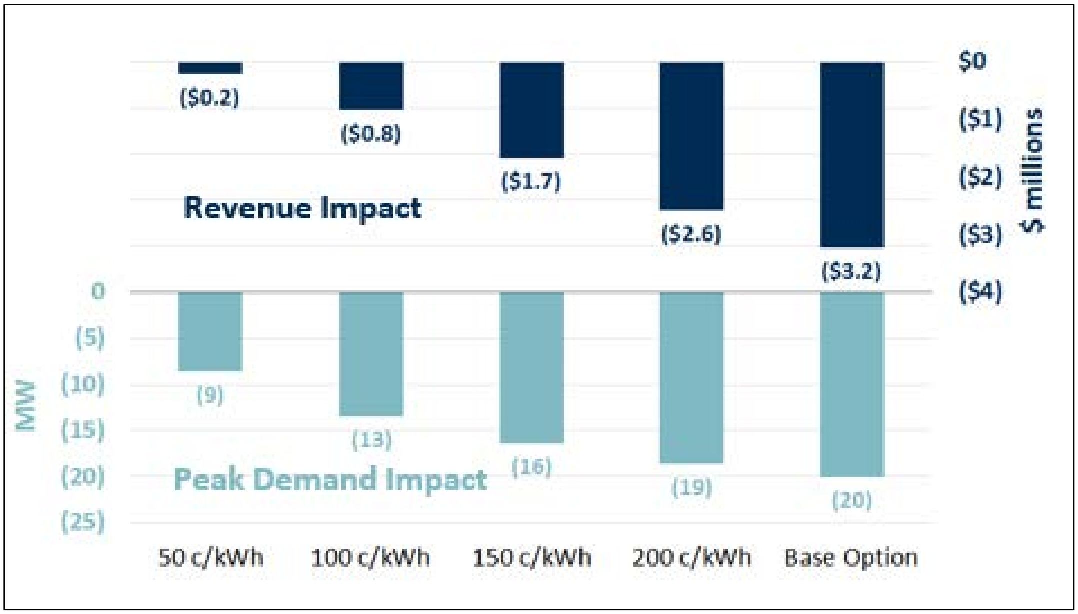
fuel cost differential), there will be a revenue shortfall for NS Power (i.e. revenue to be applied to fixed costs and fuel will be reduced).

For a well-designed TVP program this “shortfall” should be aligned with the longer-term benefit realized by all customers through the costs savings produced by reduced capacity requirements. However, it does produce a “revenue timing gap” which will need to be addressed if the TVP programs are not to simply shift costs from one group of customers (participating customers) to another (non-participating customers).

This characteristic of TVP programs also brings into focus the importance of aligning the price signals (i.e. the peak/off-peak differentials) with the real benefit realized by the TVP tariff offerings. Where the differential and revenue gap is actually greater than the benefit of reduced capacity, this will create system inefficiencies. Effectively, while it is understood that a larger differential will produce greater savings, these benefits may not be required in the near-term and/or may be available from other demand or supply alternatives more cost effectively (e.g. the Large Industrial interruptible credit).

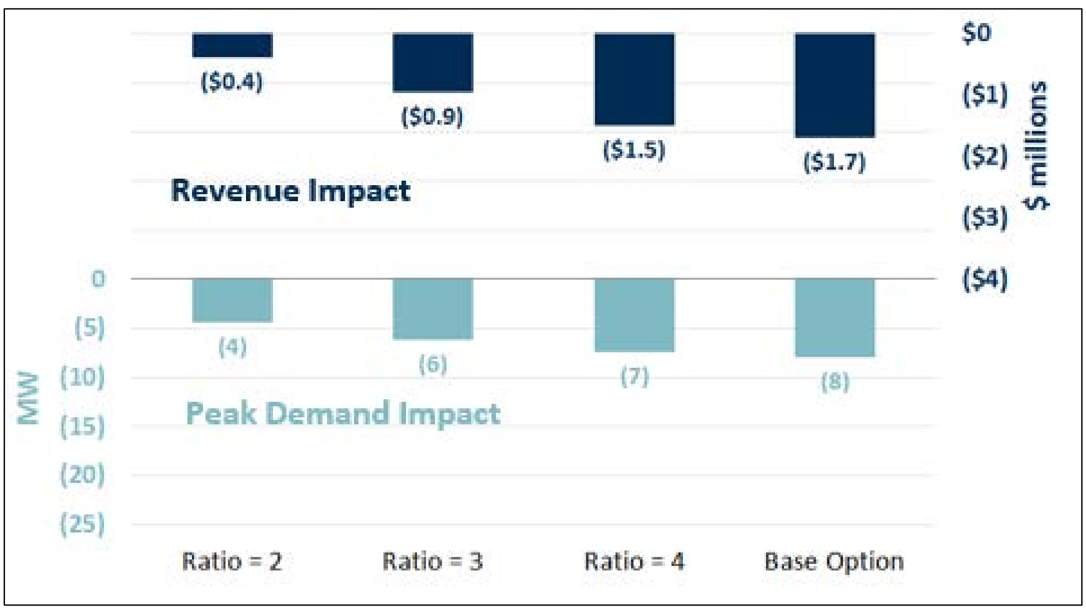
Figure 17 and **Figure 18** compare the revenue effects at the various pricing differentials for the CPP and TOU Tariffs in the Residential class.

Figure 17. Revenue Effects at various Residential CPP rates[15]



Note: The “Base Options” were the original price levels developed and tested. From here the Company tested alternatives at lower pricing differentials.

Figure 18. Revenue Effects at various Residential TOU rates[11]



Note: The “Base Options” were the original price levels developed and tested. From here the Company tested alternatives at lower pricing differentials.

[15] Appendix 6, page 12.

The results of the customer and revenue impacts across the TVP options examined are summarized in **Figure 19** for the Residential class. (Appendix 7, page 27)

Figure 19. Customer and Revenue Impact for Residential TVP Options

	Rate Simplicity	Per-Participant Peak Load Impact (%)	Aggregate Peak Impact (MW)	Revenue Impact ($M)	% whose bills instantly decrease	% whose bills decrease with DR
TOU1	Low	4.4%	7.4	1.6	69%	83%
TOU2	Low	4.4%	7.4	1.7	70%	83%
TOU3A	Medium	5.1%	8.6	1.9	64%	74%
TOU3B	Medium	4.7%	7.9	1.7	60%	72%
TOU4A	High	5.7%	9.6	2.2	69%	81%
TOU4B	High	5.3%	8.9	2.1	67%	84%
TOU4A/CPP	Low	5.9% *(TOU)* 13.6% *(CPP)*	22.8	5.4	62%	81%
TOU4B/CPP	Low	5.3% *(TOU)* 13.6% *(CPP)*	22.8	5.2	61%	83%
CPP	High	11.9% *(CPP)*	20	3.2	62%	76%

Notes: For TOU1 and TOU2, Peak Load Impact shown represent winter impacts. Aggregate Peak Load Impact is calculated assuming 15% participation. Peak Load and Revenue Impacts all represent decreases under the TVP offering. **% whose bills instantly decrease and % of whose bills decrease with DR represent the share of the 135 Residential customers in the load research sample (including 59 customers with electric heat and 76 without) who will experience lower bills under the TVP option relative to the Standard Offer Rate.**

This analysis is also presented for the Small General class (Appendix 7, page 40) and General Demand class (Appendix 7, page 42).

The Brattle analysis serves to focus attention on a key aspect of TVP program introduction: because conventional rates are developed based on class averages when you start to price this load differently across the day, customers with more favourable load profiles will benefit immediately (without any change to behaviour) while customers with load profiles that are less favourable will face increased costs from program participation. The differences can be material.

As a result of this, all else being equal:

- Customers with the favourable consumption profiles are more likely to enroll in the TVP programs.
- There will only be a capacity benefit realized if these customers with the favourable consumption profiles further adjust their load to further benefit the system profile.
- There is likely to be a material revenue shortfall created by introduction of TVP programs if take-up is material.

Proceeding with TVP introduction at this time in advance of the detailed individual customer interval data provided by AMI does present risk for participating customers and non-participating customers. It also risks undermining the growth of these programs if it provokes a negative customer reaction whether warranted or not.

Mindful of this, the electricity industry has employed different approaches including pilot and/or deployment limits in the early days of TVP roll-out. These tools are discussed in the following section of this submission.

3.8 TVP Pilot Design

The broad introduction of TVP programs represents a fundamental shift in utility pricing from the conventional tariffs offered by NS Power to customers. This innovation does represent risk both for participating and non-participating customers with respect to, among other matters:

1. What will be the take-up of the programs?

2. What will be the level of success in shifting load for customers to take advantage of the peak/off-peak price differentials?

3. Will these shifts be sustained such that the utility can revise its programs and capital investment to reduce capacity without facing future shortfalls?

In a broader sense the success of this initial TVP initiative will also be key to establishing this new tariff form as a credible tool for the utility and its customers to reduce total system cost for all customers while providing increased choice for those customers who desire this.

While there is a growing knowledge base for TVP rollouts, the success of these ventures and the design of the programs remain largely dependent on the power system characteristics, customer profiles and experience of customers to whom they are being offered. Without actual experience in a jurisdiction, there is likely to be limited confidence that the initial programs will not require refinement over time and potentially significant change.

To address this, jurisdictions have come to rely on limited deployments including pilots to test new TVP options and determine the form, scope and pace of the final TVP offerings. It is expected this will be discussed as part of the stakeholder engagement process and for this reason, the Company requested Brattle examine differing approaches to TVP deployment. Brattle's findings are presented in **Appendix 8**. Appendix 8 covers pilot planning, design, execution and analysis, customer engagement and pilot evaluation. Key elements are presented in the Appendix Recap (Appendix 8, pages 23-24), which includes the following:

- Upfront investment in pilot planning is absolutely critical for the success of the pilot.
- Seeking stakeholder input during the pilot design process and incorporating this input to the design increase the acceptability of the pilot results.
- Resist designing overly complex pilots that could easily interfere with meeting the essential objectives of the pilot.
- It is advisable to test treatments and functionality only if they are likely to be offered in full scale deployments (i.e., bill impacts and shadow bills).
- Avoid creating silos between the pilot design and marketing teams during the recruitment stage, as deviations from the recruitment plan may compromise the validity of the pilot.
- Estimation of price elasticities and consumer demand models is desirable as part of an impact evaluation study to allow estimation of the impacts from alternative rates.
- It is important to calculate sample sizes consistent with the pilot design approach that will yield statistically significant results.

- An interim impact evaluation after the first season of the pilot is useful to gauge initial results and allow course-correction if needed.[16]

3.9 Conclusions

The Company has drawn the following preliminary conclusions from the work completed to date:

1. TVP Tariffs have the potential to create benefits for the NS Power system as a whole by reducing system peak demands in an amount equaling or exceeding the 26 MW estimate that was included in the AMI capital project justification. The morning and evening winter peaks remain the primary driver of firm capacity requirement in Nova Scotia. As the Company's load profile shifts over time, and the Company's firm capacity mix changes along with the incremental cost of demand and supply-side resources, the peak/off-peak time-periods can also be expected to change.

2. Given the early stages of AMI implementation and relatively limited experience with TVP in Nova Scotia, the TVP tariffs which are less complex and do not require an established customer baseline (i.e. detailed customer usage data) would be most promising as initial TVP candidates for NS Power:

   - A Critical Peak Pricing Program is the best near-term TVP opportunity to achieve material capacity reductions.
   - A broader time-of-use based program should be offered for customers not attracted to the CPP program. While expected to provide significantly less capacity savings, a time-of-use program is expected to provide important learnings for customers and the Company. It would also serve as a helpful foundation for adding TVP offerings, potentially based on customer-specific circumstances and to support equipment-enabled time varying pricing applications (e.g. paired with batteries).

[16] Appendix 8, pages 23 and 24.

3. Final decisions concerning the determination of peak/off-peak periods, pricing differentials, TVP offerings and longer-term TVP processes to be included in the Company's application to the NSUARB require the active engagement of potential program participants and customer representatives. The Company intends to facilitate this engagement through the information presented in this filing and the proposed stakeholder engagement process proposed within this submission.

4.0 THE NOVA SCOTIA ENVIRONMENT ON THE EVE OF TVP INTRODUCTION

The benefit TVP offers is a more efficient power system profile which reduces the real-time cost of serving customers and the longer-term supply-side and demand-side resources required to meet system peaks. The value of this in the near-term and long-term is a function of the power system resources available to meet customer load. As a result, the development and implementation of TVP tariffs must consider the specific context and characteristics of the Nova Scotia system and market.

In Nova Scotia, because of the established resource mix of hydro, thermal, wind and biomass resources, the marginal cost profile is relatively flat which means the near-term value of shifting load is somewhat limited. This may change in the mid-term depending on changes in load and/or the retirement of existing generation units. Developing a common view on this is at the core of the ongoing 2020 IRP process. The list of factors which will influence the outcome of the IRP is large including:

- Changing environmental constraints
- The operating cost of existing generation assets
- The cost-effectiveness of demand-side management programming
- Costs of new technologies and availability of energy and capacity from external markets
- Development of distributed energy resources
- Development of Smart Grid technologies
- The pace of electrification[17] of the economy in Nova Scotia and the effect of this on the system load profile throughout the day and across the year.

The AMI capital application assumed load reductions would be required to avoid generation capacity additions starting in 2022 and the potential capacity value of AMI paired with TVP was

[17] Electrification refers to societal transition from fossil-fuel powered vehicles and space heating to electric vehicles and heating.

forecast on that basis. Whether a constraint is confirmed in that year through the IRP does not change the value of proceeding to introduce TVP now. It will take time to establish the foundation for this tool in Nova Scotia and determine the pricing offerings favored by potential participants which provide the greatest benefit for all NS Power customers. Regardless, the Company continues to target having TVP offerings in place coincident with completion of the AMI roll-out currently forecast for mid-year 2021. The above list of factors illustrates that significant changes are taking place in near and longer-term patterns of electricity production and consumption in Nova Scotia. After the initial offerings contemplated in this proceeding, other programs building on this ability are expected to emerge over time, including, for example, rates for electric vehicle charging.

In addition to the IRP, other associated regulatory matters include the ongoing Smart Grid Nova Scotia Project execution, NS Power and E1 collaboration on potential demand response opportunities and the Company's ongoing work with the Board and stakeholders to promote rate stability in Nova Scotia. Comment on each of these items follows.

Smart Grid Nova Scotia

In its Decision dated May 7, 2020, in the Company's Smart Grid Nova Scotia Project (M09519), the Board approved the Company's Smart Grid Project, subject to the Company's compliance filing due later this year. The Project is to extend over the period 2020-2023 and will include new service offerings, for which detailed work plans are presently being developed. The Smart Grid Nova Scotia Project and the AMI project are key initiatives both of which build on technology to develop innovative service offerings for Nova Scotia customers. Analysis and research carried out in support of AMI-enabled rates will be used to inform development of the Smart Grid programs and vice versa.

E1-NS Power Demand Response Engagement

Per the Board's directive in its approval of the 2020-2022 DSM Resource Plan,[18] E1 and NS Power are working together to develop and evaluate potential demand response initiatives, including rate design. It is anticipated that the TVP work undertaken through this submission will inform that work. It is also anticipated the E1/NS Power demand response examination will inform future TVP development.

Rate Stabilization and Fuel Adjustment Mechanisms Considerations

Working with regulatory stakeholders and the Board, NS Power has established a decade of rate stability in our Province and rate increases which have been below the level of inflation. This is despite volatility in fuel and purchased power cost drivers, increasing environmental constraints and a substantial demand-side management program which has reduced load growth.

NS Power's rate structures include a large portion of fixed cost recovery in the energy rate. This is particularly true for the Residential customer class which accounts for approximately 60 percent of the Company's fixed cost recovery.

It is likely that in the near-term, implementation of the peak/off-peak pricing differentials required to incent customers to shift load will create near-term revenue shortfalls and, if large enough would threaten rate stability. There are mechanisms available to address this (e.g. Lost Revenue Adjustment Mechanisms) that will need to be assessed and likely incorporated within the TVP project roll-out.

Fuel Adjustment Mechanism

Similarly, NS Power has operated with a Fuel Adjustment Mechanism (FAM) in place since 2009. Because increasingly fuel and purchased power cost is composed of fixed costs (e.g. Independent Power Produce contracts and the Maritime Link assessment), consideration will need to be given

[18] M09096, Decision 2019 NSUARB 105, August 2, 2019, paragraph 49.

to the effect of TVP programs on FAM cost drivers and the associated recovery of fuel costs across and within customer classes.

5.0 UPDATE ON AMI ROLLOUT

The installation of smart meters under the AMI project started in July 2019. As of June 26, 2020, over 110,000 meters, approximately 21 per cent of the total, have been installed.

The AMI program allows customers to opt out of having a smart meter installed if they wish to continue to use a manually-read electricity meter. To date, the rate of opt-out requests is approximately 1.5 percent.

The meter installation timeline has been affected by the COVID-19 pandemic. On March 17, 2020 NS Power suspended smart meter upgrades in order to comply with COVID-19 prevention recommendations.[19] While the upgrade program was suspended. NS Power reviewed and refined its safety protocols, acquired additional Personal Protective Equipment and updated its existing customer communications. As restrictions eased, the Company provided additional training for employees and contractors to ensure smart meter upgrades resumed in a way that was safe for customers and the installation crews. Smart meter upgrades resumed on June 1, 2020 as the Province began lifting various restrictions related to COVID-19. During the period that meter installation was suspended, work continued on other components of the AMI system, such as the integration of back office systems and the installation of the Meter Data Management System.

Barring additional pandemic impacts, NS Power anticipates mass meter upgrades and supporting software and integration will be complete by mid-2021.

[19] On March 22, Nova Scotia declared a provincial state of emergency under the Health Protection Act. As part of that declaration, the Premier of Nova Scotia and the Chief Medical Officer of Health asked residents, and those working in non-essential roles, to remain at home.

6.0 STAKEHOLDER ENGAGEMENT AND REGULATORY PROCEEDING

The previous sections of this submission discuss general matters to be considered as part of TVP development and implementation. These issues, combined with information developed through the Company's work to date, confirm there are fundamental matters requiring resolution before proceeding with TVP in Nova Scotia. Because of the variety of options and paths available to the Company and its customers, it is appropriate these matters be vetted with stakeholders in advance of a formal application to the Board and, where possible, consensus be developed.

It is the Company's view that the most effective and efficient forum for doing so is stakeholder engagement in advance of an application to approve the TVP tariffs. NS Power is therefore requesting that a proceeding be initiated to develop, approve, and implement TVP tariffs. The Company proposes that such a proceeding include a Board approved process and timeline for NS Power to undertake stakeholder engagement and file an application for the approval of proposed TVP tariffs, including any regulatory process that may be required to approve proposed TVP tariffs.

The period between this filing of this submission and the anticipated substantial completion of the AMI rollout by mid-year 2021 provides the necessary time to undertake this level of stakeholder engagement, while still allowing the normal time required for a full regulatory proceeding to approve the TVP tariffs.

Key issues to be resolved as part of the stakeholder engagement include the following:

1. Value of load shifting to customers in the near and longer-terms
2. Annual and daily peak-off-peak period definitions
3. Initial TVP program offerings
4. Peak/off-peak pricing differentials
5. Customer engagement

6. Processes to address concerns of low-income customers and small businesses with respect to the introduction of TVP
7. Program introduction (e.g. general offerings versus pilots)
8. Associated considerations (e.g. lost revenue adjustment mechanisms)

7.0 REQUEST OF NSUARB

As set out in Section 6, NS Power is requesting the Board initiate a two-part proceeding to facilitate the development and approval of TVP Tariffs. As described herein the Company proposes the regulatory proceeding be approached in two parts:

- Part 1: It is proposed that Part 1 of the proceeding is a consultative process focused on stakeholder engagement beginning with the examination, review and refinement with stakeholders of the materials presented herein and concluding with the filing of an application by the Company with the Board for approval of the proposed TVP tariffs. Part 1 would include technical conferences and data exchanges among the parties. The Board's opening of the proceeding would provide a vehicle for informing interested parties of the application and establishing a formal record of parties to have received related materials. NS Power requests the Board provide a timeline in which Part 1 is to be completed, including the filing of an application for approval of TVP tariffs and that the conclusion of this timeline be no later than November 30, 2020, so as to allow sufficient time for the Board to make a determination on the application and TVP tariffs to be implanted prior to the completion of the AMI roll-out currently scheduled for mid-2021.

- Part 2: Once initiated by the filing of an application for approval of TVP tariffs, Part 2 of the proceeding would then consist of the regulatory process required for the Board to hear the application and make a determination.

It is the Company's expectation that the process configured in this manner will allow the TVP Tariffs to be available contemporaneous with the completion of the AMI roll-out currently scheduled for mid-2021.

7.1 Recommended Regulatory Process

As noted in the foregoing, NS Power proposes the Board open a two-part proceeding to facilitate stakeholder input and approval of TVP tariffs.

Opening the proceeding will serve to notify parties of the Company's intent to make application for TVP tariffs and provide interested parties access to the materials included in this submission. Where parties beyond the customary regulatory participants (e.g. customer advocates and EfficiencyOne) determine they wish to participate in the development of the Company's submission, the Board notice will provide an opportunity to do so.

NS Power is proposing Part 1 of the proceeding to be consultative in nature and serve as a stakeholder engagement process. Recognizing the early stages of TVP development in Nova Scotia, the process and work to be undertaken in Part 1 would focus on technical conference(s) intended to review the materials submitted in this filing and provide an introduction to TVP. The sessions would include the Company's TVP pricing consultant, Brattle. The technical conferences would be used to determine issues to be resolved as part of the formal regulatory process, areas requiring additional examination and areas of consensus and disagreement among parties.

Once the TVP Program issues are established, additional information exchanges would be undertaken by the Company, likely through additional technical conferences and data requests and submissions shared among parties. Consistent with similar proceedings it would be the Company's intention to provide the Board with a complete record of exchanges among parties throughout Part 1. It is also anticipated and proposed that Board staff and Board Counsel's consultants would participate in the stakeholder engagement phase of the process.

NS Power is proposing that the Board provide a deadline for the completion of Part 1, including the filing of an application by NS Power for approval of TVP tariffs. Upon the filing of the TVP tariff application by NS Power, Part 2 of the proceeding would then be initiated and would consist of the regulatory process required for the Board to hear the application and make a determination. NS Power's intention is to attempt to achieve as much consensus as is feasible with stakeholders prior to filing the application.

A proposed high-level summary of this two-part process is set out in **Figure 20**, with approximate timelines.

Figure 20. Two-Part Tariff Development Process

Part 1	
1. Filing of • NS Power preliminary findings and recommendations • Recommended stakeholder engagement process	June 30, 2020
2. NSUARB to provide direction / open proceeding	July 2020
3. Technical Conference #1 Introduction to Time-Varying Pricing	July/August 2020
4. Participant Comments on NS Power submission	August 2020
5. Data exchanges, consensus development, further conferences as required	September/October 2020

Part 2	
1. NS Power submits Tariff Application, ideally as a consensus document	November 2020
2. Regulatory Proceeding	December 2020 – May 2021
3. Implementation of NSUARB Decision	July 2021

8.0 CONCLUSION

Over the past decade, Nova Scotia has developed sophisticated and transparent resource planning processes across the electricity sector which incorporate supply-side and demand-side options. With technological grid advancements and a growing role for distributed energy resources, it is now appropriate to expand our focus on demand response resources. The implementation of AMI will make this broadly possible. The power of TVP makes it technically and financially viable.

The work of NS Power with Brattle has served to create a comprehensive record of matters to be considered as part of the broad introduction of TVP in our Province. While a potentially powerful demand response tool, these tariffs represent fundamental change for the Company and our customers. Care is required in ensuring the tool is well understood by both participating and non-participating customers and creates a foundation on which the Company and its customers can rely for years to come.

Consistent with this, NS Power is proposing a broad and transparent stakeholder process to launch this undertaking. It is the Company's expectation that working directly with potential customers and customer representatives in advance of finalizing our application will lead to an improved application to the NSUARB that has the broad support of parties and establishes a solid, long-term, effective, and efficient demand response tool for customers.

Time Varying Pricing (TVP) Options

ASSESSMENT OF ALTERNATIVES

PRESENTED TO
NS Power

PRESENTED BY
Ahmad Faruqui, Ph.D.
Sanem Sergici, Ph.D.

June 2020

THE Brattle GROUP

AMI enables a variety of time-varying pricing options

Rate	Definition
1- Time-of-Use *(TOU)*	The day is divided into peak and off-peak time periods. Prices are higher during the peak period hours to reflect the higher cost of supplying energy during that period
2- Critical Peak Pricing *(CPP)*	Customers pay higher prices during critical events when system costs are highest or when the power grid is severely stressed
3- Peak Time Rebates *(PTR)*	Customers are paid for load reductions on critical days, estimated relative to a forecast of what the customer would have otherwise consumed (their "baseline")
4- Variable Peak Pricing *(VPP)*	During alternative peak days, customers pay a rate that varies by day to reflect dynamic variations in the cost of electricity
5- Real-Time Pricing *(RTP)*	Customers pay prices that vary by the hour to reflect the actual cost of electricity
6- Two-part Real-Time Pricing *(2-part RTP)*	Customer's current rate applies to a baseline level of consumption. A second, marginal cost based, price applies to deviations from the baseline consumption
7- Three-part Rates *(3-part Rates)*	In addition to volumetric energy charge and fixed charge, customers are also charged based on peak demand, typically measured over a span of 15, 30, or 60 minutes
8- Fixed Bill with Incentives	Customers pay a fixed monthly bill accompanied with tools for lowering the bill (such as incentives for lowering peak usage)

Applicability to Customer Classes

All of the time varying prices introduced in the earlier slide (with the exception of fixed bills with incentives) are applicable to residential, small general and general service classes

In many jurisdictions, larger non-residential customers are already on some form of default TOU, CPP or RTP rates

1- Time-of-Use (TOU) Rate

The day is divided into time periods which define peak and off-peak periods. Prices are higher during the peak period to reflect the higher cost of supplying energy

Pros	Cons
• Better captures the **natural variation in the cost of supplying electricity** to customers • Helps **raise load factors** and **lower average costs** for all customers • Reduces inter-customer **cross-subsidies**	• **Opt-in deployments create a revenue loss issue** which has to be dealt with either through decoupling (California), a Lost Revenue Adjustment Mechanism (Oklahoma), or building the revenue loss into the TOU rate structure (Xcel Energy Colorado) • There may be **customer dissatisfaction** with having to modify behavior to solve what customers essentially view as the utility's problem • Would raise bills for customers with peakier than average load shapes, who thus may not enroll even though they drive up costs for all customers. Meanwhile, customers with higher than average load factors may receive lower bills without changing their behavior, creating a revenue loss issue for the utility

2- Critical Peak Pricing (CPP) Rate

Customers pay higher prices during critical events when system costs are highest or when the power grid is severely stressed

Pros	Cons
• Just a few critical events can account for a **high share of demand**. For the typical utility, the top 1% of hours with the highest usage may account for 8%-18% of annual peak load, requiring peaking capacity to be kept idle at high cost to meet this contingency • More **responsive to changing conditions** than TOU, allowing for more timely load reductions during critical events and reducing need for peaking capacity	• Customers tend to become anxious just from looking at the high prices charged during the critical peak hours. While some respond, some will just drop out of the rate

3- Peak Time Rebate (PTR) Rate

Customers receive credits for load reductions during critical events, estimated relative to a forecast of what the customer would have otherwise consumed (their “baseline”)

Pros	Cons
• Instead of charging a higher price during the critical hours, provides a rebate during those hours, which may be more **appealing to customers** • The scarcity value of providing power during the critical hours is conveyed as an **opportunity cost** (lost opportunity for earning a rebate) and not as a higher price (CPP) • Similar to CPP, more responsive than TOU in addressing extreme temperature events	• In order to compute the rebate, the utility needs to know what the customer would have consumed if the rebate had not been given (i.e., **estimate baseline usage**) • Since the price does not change in either the peak or the off-peak period, the PTR rate is **not as cost-reflective** as the CPP tariff or even the TOU tariff • The source of the PTR payments becomes an issue to resolve for large scale deployments

4- Variable Peak Pricing (VPP)

During event days, customers pay a rate that varies by day to reflect dynamic variations in the cost of electricity.

Pros	Cons

• More precise match of actual costs to customer prices
  ◦ May have four rates, for example Oklahoma has Low, Standard, High, Critical
  ◦ May be tied to real-time prices applicable on the event day
• Used with programmable thermostats would make it easier for customers to control heating
	• More complex for customers to understand and respond to on one day (or less) notice.
	• In Oklahoma there are 86 days that customers are notified and one of the four prices is used.

5- Real-Time Pricing (RTP)

Customers pay prices that vary by the hour to reflect the actual cost of electricity

Pros	Cons
• Hourly variation in energy prices passes through variations in wholesale energy markets to customers (often supplemented with a way to recover capacity costs), **incentivizing customers** to use less when prices are high and use more when prices are low • The need for such a product will grow as more renewable energy resources are interjected into the resource mix of utilities. Renewable energy resources, mostly solar and wind, are intermittent, whereas RTP can inject **load flexibility** and ensure **reliability**	• **Bill volatility** can be quite severe. To broaden its appeal, the RTP product would probably need to be redesigned to shield customers from massive bill volatility, for instance through price caps and collars

6- Two-Part Real Time Pricing

The first part of the rate is set equal to the customer's existing bill and is contingent on maintaining the existing load shape, while the second part is based on marginal costs and applies to deviations from the existing load shape

Pros	Cons
• The two components **balance** each other, with the first part guaranteeing stable prices for some amount of load, while the second part responds to variability in marginal prices • This exposes the customer to **less risk**, but still provides an incentive to reduce usage in high-cost hours and achieve bill savings	• The existing load shape has to be defined in a manner similar to defining the baseline load shape for payments of PTR, which is difficult to do for new customers

7- Three-part Rates

Customers are charged based on their peak electricity consumption, typically over a span of 15, 30, or 60 minutes

Pros	Cons
• Most **cost-reflective** rate design, i.e. demand related costs are recovered via demand-based billing determinant, energy related costs are recovered via volumetric billing determinant and fixed costs are recovered via fixed/customer charges • Demand charge would ideally have two components: Coincident Peak and Non-Coincident Peak demand • Increases cost-recovery certainty for utilities, especially for those jurisdictions with high penetrations of distributed generation	• It may be difficult to manage from a customer perspective as the demand concept is not immediately intuitive for customers • However, there are various ways to educate customers so they can get better at managing their load and achieve bill savings under 3-part rates

8- Fixed Bill with Incentives

Customers pay a fixed monthly bill accompanied with tools for lowering the bill (such as incentives for lowering peak usage, DR program participation, PTR)

Pros	Cons
• There is **increasing consumer interest** in guaranteed bills, whether for watching movies (e.g., via Netflix) or for buying products and services, while customers have long been familiar with the all-you-can-eat buffet • Some utilities have been offering a guaranteed bill product for many years, going back to a “weather-proof” bill offered by a natural gas utility in the southern US in the late 1990s • If the guaranteed bill can be coupled with a peak-time rebate, it offers customers an opportunity to lower the bill by responding to system conditions in a limited number of hours	• When additional incentives are not paired with fixed bills, customers face **zero marginal cost** and have no incentive to use energy efficiently

THE POWER OF **ECONOMICS**

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Time-Varying Pricing Jurisdictional Scan

LESSONS LEARNED, & RECOMMENDATIONS FOR MOVING FORWARD

PRESENTED TO

NS Power

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June 2020

THE Brattle GROUP

Overview

One of the leading benefits of AMI is the enablement of TVPs and the harnessing of the load flexibility capability created by these rates

- As of 2018, almost 87 million smart meters have been deployed to more than 60% of U.S. homes (*)
- Smart meter penetration is expected to increase to 81% of North American homes by 2024 (**)

In Ontario, TVPs are deployed to all residential and small commercial and industrial customers and 90% are taking service on TVRs

In the U.S., TVPs are only deployed to 4% of U.S. residential customers so there is a huge opportunity for expansion

Notes:
(*) EIA, "Nearly half of all U.S. electricity customers have smart meters," December 6, 2017, https://www.eia.gov/todayinenergy/detail.php?id=34012.
(**) Smart Energy, "Smart meter penetration in North America will reach 81% by 2024," July 5, 2019, https://www.smart-energy.com/industry-sectors/smart-meters/smart-meter-penetration-in-north-america-will-reach-81-by-2024/

AMI enables a variety of time-varying pricing options

Rate	Definition
1- Time-of-Use *(TOU)*	The day is divided into peak and off-peak time periods. Prices are higher during the peak period hours to reflect the higher cost of supplying energy during that period
2- Critical Peak Pricing *(CPP)*	Customers pay higher prices during critical events when system costs are highest or when the power grid is severely stressed
3- Peak Time Rebates *(PTR)*	Customers are paid for load reductions on critical days, estimated relative to a forecast of what the customer would have otherwise consumed (their “baseline”)
4- Variable Peak Pricing *(VPP)*	During alternative peak days, customers pay a rate that varies by day to reflect dynamic variations in the cost of electricity
5- Real-Time Pricing *(RTP)*	Customers pay prices that vary by the hour to reflect the actual cost of electricity
6- Two-part Real-Time Pricing *(2-part RTP)*	Customer’s current rate applies to a baseline level of consumption. A second, marginal cost based, price applies to deviations from the baseline consumption
7- Three-part Rates *(3-part Rates)*	In addition to volumetric energy charge and fixed charge, customers are also charged based on peak demand, typically measured over a span of 15, 30, or 60 minutes
8- Fixed Bill with Incentives	Customers pay a fixed monthly bill accompanied with tools for lowering the bill (such as incentives for lowering peak usage)

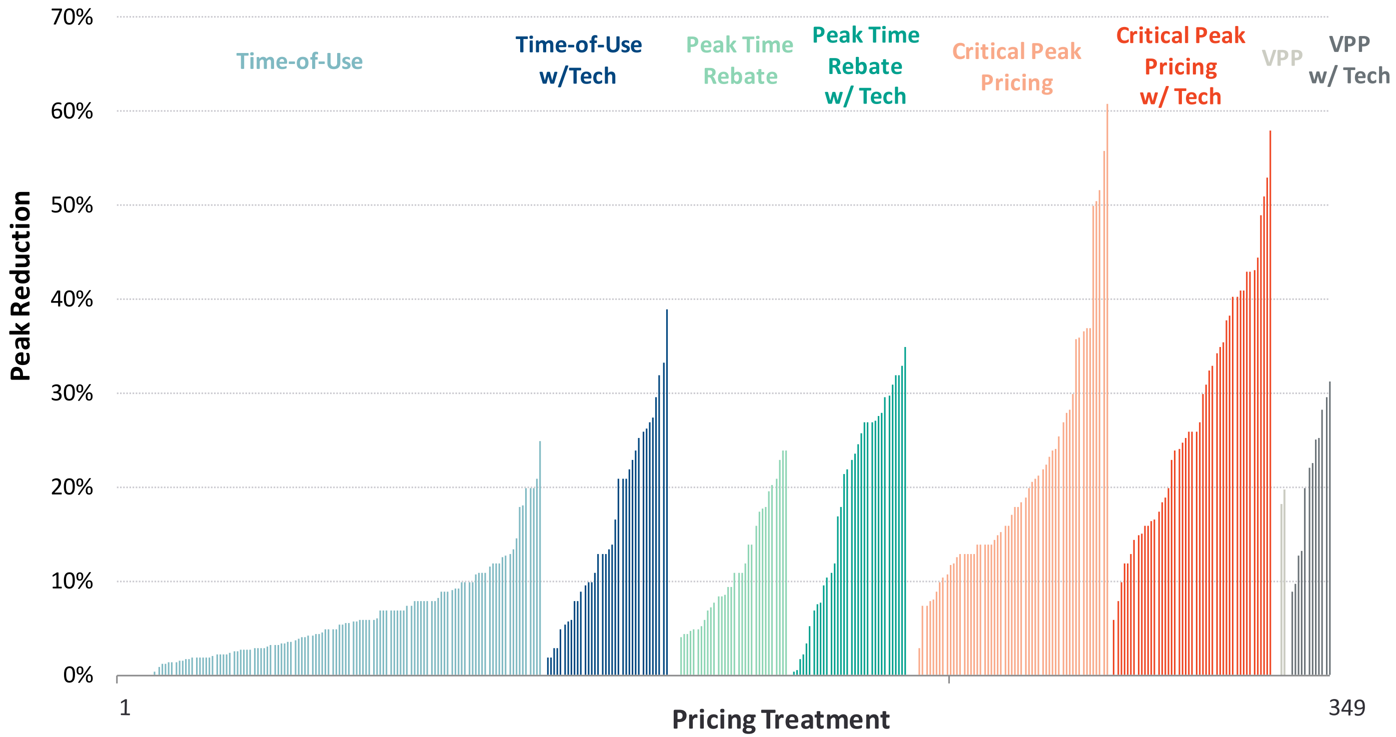
Residential TVPs have been deployed around the world and are being considered in Australia and New Zealand

	Type of Rate	Applicability	Participating Customers
Oklahoma *(OGE)*	Variable Peak Pricing (VPP)	Opt-in	20% (130,000)
Maryland *(BGE, Pepco, Delmarva)*	Peak Time Rebate (PTR)	Default	80%
Ontario, Canada	Time-of-Use (TOU)	Default	90% (3.6 million)
Great Britain	Time-of-Use (TOU)	Opt-in	13% (3.5 million)
Hong Kong *(CLP Power Limited)*	Peak Time Rebate (PTR)	Opt-in	27,000
Arizona *(APS, SRP)*	Time-of-Use (TOU)	Opt-in	APS: 57%, SRP: 36%
California *(PG&E, SCE, SDG&E)*	Time-of-Use (TOU)	Default (2020)	TBD – 75-90%*
California *(SMUD)*	Time-of-Use (TOU)	Default	75-90%*
Colorado *(Fort Collins)*	Time-of-Use (TOU)	Mandatory	100%
Illinois *(ComEd, Ameren IL)*	Real Time Pricing (RTP)	Opt-in	50,000
Michigan *(Consumers Energy)*	Time-of-Use (TOU)	Default (2020)	TBD – 75-90%*
France	Time-of-Use (TOU)	Opt-in	50%
Spain	Real Time Pricing (RTP)	Default	40%
Italy	Time-of-Use (TOU)	Default	75-90%*

*Estimated participation based on historical trends

There is compelling evidence from 300+ pilots that customers respond to TVPs

Pilots feature a combination of rate designs (TOU, CPP, PTR, and VPP), which influence the level of peak reduction



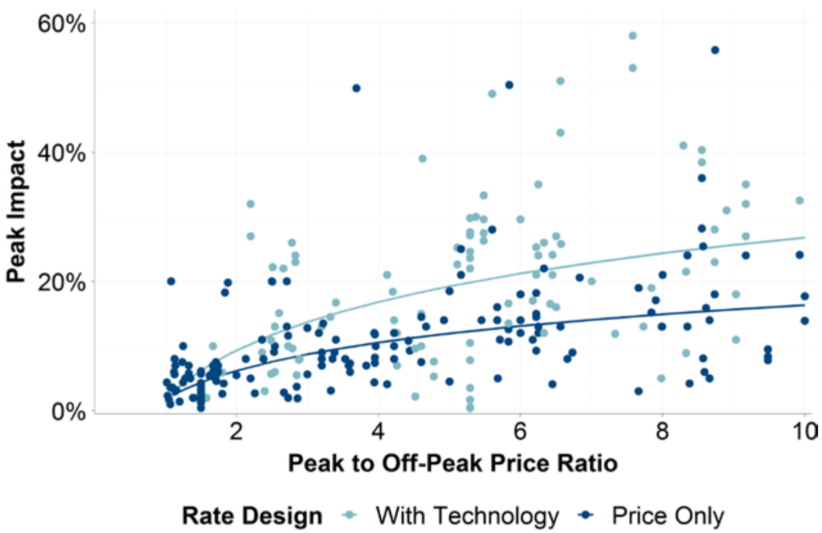
Source: The Brattle Group. Peak reductions represent results from 349 pricing treatments collected in the Arcturus 2.0 database.

The magnitude of demand response also varies by price ratio

On average, residential customers reduce their on-peak usage by 6.5% for every 10% increase in the peak-to-off-peak price ratio

In the presence of enabling technology such as smart thermostats, the effect is stronger

- On average, customers enrolled on TVPs paired with enabling technologies reduce peak usage by 11% for every 10% increase in the price ratio



Source: Ahmad Faruqui , Sanem Sergici, and Cody Warner, "Arcturus 2.0: International Evidence on Time-Varying Rates," The Electricity Journal, 2017.

Winter-peaking utility experience with TVPs

	Study Years	Form(s) of TVP	Peak Price Ratio	Peak Impact	Notes
Puget Sound Energy	2001-2002	TOU	1.4	~5% reduction in peak period usage per month over a 15-month period	Involved four pricing periods. Customer response was encouraging in the first year, but declined in the second after a reduction in the peak price ratio and negative media coverage (in one quarter, customers experienced an average 80 c/month *loss*)
Pacific Power	2004	TOU	1.7-2.1	9% in winter morning, 8% in winter evening	Did not meet cost-effectiveness from a total resource cost perspective, in part due to low participation coupled with a high dropout rate
BC Hydro	2006-2008	TOU, TOU/CPP	*TOU:* 3-6 *CPP:* 7.9	2%-4% reduction in on-peak TOU period, 5% in critical peak period	Analysis of the second winter found that enabling tech (in-home display) doubled estimated TOU and CPP reductions
Hydro-Québec	2008-2010	TOU, TOU/CPP	*TOU:* 1.4-1.7 *CPP:* 3	Only significant in critical peak period under TOU/CPP rate (~6% reduction)	Hydro-Québec is now gradually offering opt-in PTR and CPP rates, detailed in a later slide
Portland General Electric	2016-2018	TOU, PTR, TOU/PTR	*TOU:* 1.8-2.6	*TOU:* Only statistically significant in summer *PTR:* 7%-12% winter demand savings for opt-in, 5% for opt-out PTR *TOU/PTR:* 1%-5%	Usage reductions were less significant in winter than summer, in part because approximately 60% of TOU participants have gas heating

U.S. Benchmark

Overview of TVR Offerings

According to 2018 EIA Form-861, **322 U.S. utilities offer at least one form of time-varying rate** to residential customers

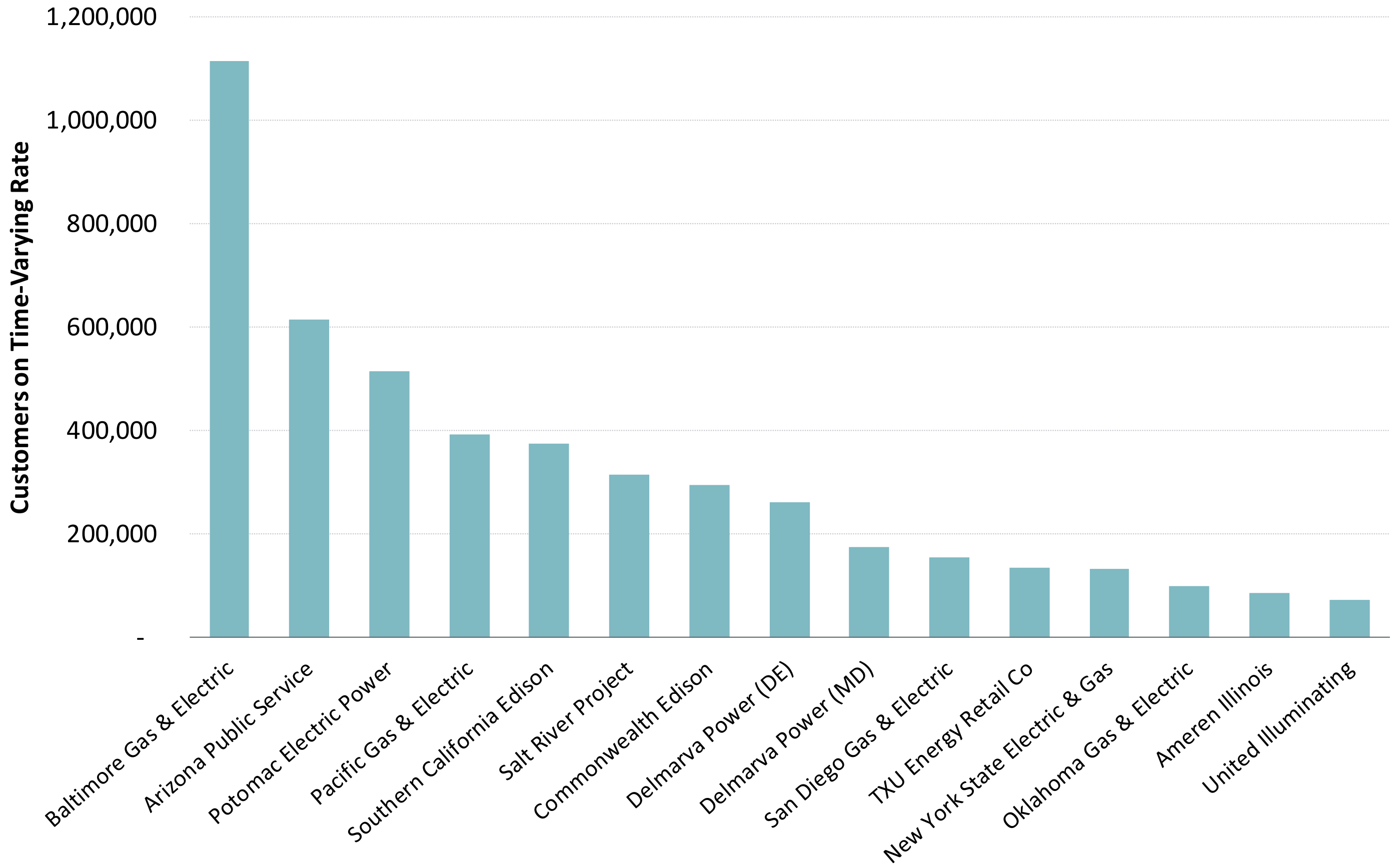
- 303 offer Time-of-Use (TOU)
- 29 offer Critical Peak Pricing (CPP)
- 14 offer Peak Time Rebate (PTR)
- 9 offer Variable Peak Pricing (VPP)
- 6 offer Real-Time Pricing (RTP)

Altogether, **5.5 million customers** (or 4% of all residential customers) are enrolled on one of these time-varying rates

U.S. Benchmark

Largest TVP Deployments

The following **15 utilities accounted for 86% of all customers** enrolled on a time-varying rate



Arizona
Time-of-Use Rates (1/2)

Arizona Public Service (APS) leads all U.S. utilities with the largest number of customers enrolled on an opt-in TOU rate

- Over 600,000 customers, or approximately 56% of its 1.1 million residential customers, are on a TOU rate

APS offers five residential rate schedules, of which three are TOU rates

- Saver Choice ("R-TOU-E") includes seasonal on-peak and off-peak energy charges, with a ratio of slightly over 2:1 and an on-peak period of 3-8 PM Monday-Friday. There is also a winter-only super off-peak energy charge
- The Saver Choice Plus ("R-2") and Saver Choice Max ("R-3") rates have a smaller peak/off-peak ratio and no super off-peak period, but include a demand charge
- The other two non-TOU rates are restricted to customers with an average usage of less than 1,000 kWh

References:

APS, Service Plans, https://www.aps.com/en/Utility/Regulatory-and-Legal/Rates-Schedules-and-Adjustors

Arizona

Time-of-Use Rates (2/2)

Salt River Project, Arizona's second largest utility, also offers three TOU options

- Roughly 315,000 customers, or 33% of its nearly 1 million residential customers, are enrolled on a TOU rate
- The SRP TOU Plan ("E-26") defines on-peak hours as 2-8 PM in summer (P/OP ratio of 2.9) and 5-9 AM and 5-9 PM in winter (P/OP ratio of 1.4)
- SRP's Residential Super Peak TOU plan offers two options, E-21 and E-22, both of which charge higher costs in a three hour week-day time frame
  - The E-21 plan defines an on-peak period of weekdays 3-6 PM, while the E-22 plan's peak period covers weekdays 4-7 PM
  - Both options have an peak/off-peak ratio of 3.5:1 in the summer (May-June, Sept-Oct.), 4:1 in the summer peak (July, August), and 1.4:1 in the winter (Nov-April)
  - Customers receive a 90-day bill protection. If their first three bills are higher than they would have been on the default Basic price plan, they are credited the difference and switched back to the Basic plan

References:

SRP, Time-of-Use Price Plan, https://www.srpnet.com/prices/home/tou.aspx
SRP, EZ-3 Price Plan, https://www.srpnet.com/prices/home/ez3.aspx

California

Time-of-Use Rates (1/3)

Pacific Gas & Electric (PG&E) currently has ~400,000 customers on an opt-in time-varying rate

- Currently, customers can opt into an E-TOU-B option with peak hours from weekdays 4-9 PM, capped at 225,000 customers
- Electric vehicle owners can sign up for rate schedule EV-B, a residential TOU service that requires the installation of a separate meter. EV-B charges lowest costs in the 11 PM – 7 AM off-peak period, and higher costs in the peak (2-9 PM) and partial-peak (7 AM-2 PM and 9-11 PM) periods
  - Some customers are on an EV-A option that combines the vehicle's electricity costs with those of the customer's residence, but this rate is now closed to new enrollments

The other two California investor-owned utilities, Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E), have approximately 370,000 and 155,000 customers on opt-in time-varying rates respectively

- Almost 99% of customers that were moved to either SCE or SDG&E's TOU pilots chose to stay on a TOU plan

References: PG&E, Tariffs, https://www.pge.com/tariffs/index.page

California
Time-of-Use Rates (2/3)

All three California investor-owned-utilities are planning the deployment of default TOU rates

- SDG&E began its rollout in March 2019, offering two TOU plans with a 4-9 PM peak period and a 2.1:1 peak/off-peak period, as well as an additional super off-peak period from 12-6 AM
- PG&E and SCE will transition customers in October 2020

The CPUC has ordered two customer guarantees as part of the rollout

- Customers will be provide an estimate of how their TOU bill compares with what their bill would have been on their old rate so they can see if they saved money or not
- A 12-month bill guarantee, such that customers whose first-year bill under the new TOU rate is higher than it would have been under their old rate will be credited the difference

References:

Utility Dive, California utilities prep nation's biggest time-of-use rate rollout, https://www.utilitydive.com/news/california-utilities-prep-nations-biggest-time-of-use-rate-roll-out/543402/

California
Time-of-Use Rates (3/3)

Sacramento Municipal Utility District (SMUD), one of the largest U.S. municipalities, already transitioned in 2019 to default TOU rates for its 600,000 residential customers

- The TOU rate has a peak period of 5-8 PM year around
  - Summer rates, which are higher than in non-summer, feature a peak rate of $0.2941/kWh, an off-peak rate of $0.1209, and an additional mid-peak rate (for noon-5 PM and 8 PM-midnight) of $0.1671/kWh
- Customers without rooftop solar can opt out and elect the Fixed Rate, which charges three different flat volumetric prices based on three different periods of the year
  - SMUD estimates the Fixed Rate is approximately 4% higher than the TOU rate

Before filing for TOU, SMUD conducted a successful pilot program in 2012 and 2013 testing TOU, CPP, and TOU/CPP rates

- The pilot found significant load shifting, customer preference for TOU over CPP, and ~50% higher average reductions with opt-in versus opt-out (which had 90% retention)

References:

SMUD, Time-of-Day Rates, https://www.smud.org/en/Rate-Information/Time-of-Day-rates/Time-of-Day-5-8pm-Rate
SMUD, SmartPricing Options Final Evaluation, https://www.smud.org/-/media/Documents/Corporate/About-Us/Energy-Research-and-Development/research-SmartPricing-options-final-evaluation.ashx

Michigan
Time-of-Use Rates

In the summer of 2019, Consumers Energy rolled out a TOU "Summer Peak Rate" to approximately 3% of its 1.6 million customers, selecting communities that were representative of its service territory

- Summer Peak Rates charges a on-peak rate on weekdays 2-7 PM (June-September), that is about 1.5 times higher than the off-peak rate
- The off-peak rate is the regular rate from October-May

The plan was to default all residential customers to the TOU plan in June 2020, however this plan has been delayed until 2021

- The rollout is part of Consumers' "Clean Energy Plan", which commits to 90% clean energy by 2040
- As part of the default TOU rollout, Consumers will deploy a bill impact tool so customers can see how their bill would differ under the new rate

References:

Consumers Energy, Summer Peak Rate, https://www.consumersenergy.com/residential/rates/electric-rates-and-programs/summer-time-of-use-rate

Maryland
Peak Time Rebate Programs

Baltimore Gas & Electric (BGE), Potomac Electric Power Co (Pepco), and Delmarva Power offer *opt-out* PTR programs that reward customers with $1.25/kWh bill credits for reducing energy usage during a handful of summer peak demand events

- Customers receive an alert, usually *the day before the savings event*, and can choose whether or not to participate in a particular event by reducing their use
- Energy and peak demand reductions are bid directly into the PJM wholesale market

All three utilities offer the program on an opt-out basis, resulting in the enrollment of nearly all customers with smart meters

- According to EIA Form-861, 1.1 million (96%) of BGE customers, 516,000 (98%) of Pepco customers, and 175,000 (98%) of Delmarva customers are enrolled
- In 2018, BGE reported a 76% participation rate among its 1.1 million eligible customers, with an average bill credit of $6.30. BGE's Energy Savings Days program is currently largest-scale deployment of dynamic pricing by any U.S. utility

References:

BGE, Energy Savings Days, https://www.bge.com/WaysToSave/ForYourHome/Pages/EnergySavingsDays.aspx
Pepco, Peak Energy Savings Credit, https://www.pepco.com/WaysToSave/ForYourHome/Pages/MD/AboutPeakEnergySavingsCredit.aspx
Delmarva, Peak Energy Savings Credit, https://www.delmarva.com/WaysToSave/ForYourHome/Pages/DE/PeakEnergySavingsCredit.aspx

Illinois
Peak Time Rebate Programs

Commonwealth Edison (ComEd) fully deployed smart meters to its 4 million customers between 2013-2019

All customers with smart meters are eligible for the Peak Time Savings Program, with approximately 275,000 customers enrolled in summer 2018

- Customers earn a credit of $1 for every kWh saved relative to their expected usage, where a weather-normalized expected usage is calculated based on usage history. ComEd estimates that most customers will receive a $1-$12 bill credit for each event
- Customers are notified *on the day of the event*, as early as 9 AM up to 30 minutes before the event
- Historically, ComEd has announced between 3 to 5 events during each summer season, with each event lasting a few hours between 11 AM – 7 PM
- Customers may not participate simultaneously in ComEd's Central AC Cycling program

References:

ComEd, Peak Time Savings, https://www.comed.com/WaysToSave/ForYourHome/Pages/PeakTimeSavings.aspx

ComEd, Peak Time Savings Program Annual Report, https://www.icc.illinois.gov/docket/files.aspx?no=P2012-0484&docId=290476

Illinois
Real-Time Pricing (1/2)

ComEd also offers its residential customers an Hourly Pricing Program

- Under ComEd's Hourly Pricing program, prices vary hourly according to wholesale market prices. Customers can access online energy-management tools and view their hourly usage from the prior day as well as day-ahead prices for the next day
- In 2018, the 30,251 Hourly Pricing participants saved an average of 10% (~$75) compared to ComEd's standard fixed-price rate
- An analysis by Citizens Utility Board and EDF found 97% of ComEd customers would have seen lower bills on RTP without changing behavior. The average customer would have saved $86 (13.2%) per year

	All Customers		Top 5% of Savers		Bottom 5% of Savers	
Rate	Amount	% of Bill	Amount	% of Bill	Amount	% of Bill
Average Annual Savings	$86.63	13.2%	$103.76	31.0%	$0.62	0.0%
Median Savings	$69.78	12.6%	$68.42	28.8%	$0.77	0.3%
Total Annual Savings	$29.8 m	-	$3.95 m	-	$10,121	-

References:
ComEd, Hourly Pricing Program 2018 Annual Report, https://www.icc.illinois.gov/docket/files.aspx?no=15-0602&docId=285594
"The Costs and Benefits of Real-Time Pricing," CUB; EDF, November 14, 2017, https://citizensutilityboard.org/wp-content/uploads/2017/11/20171114_FinalRealTimePricingWhitepaper.pdf

Illinois
Real-Time Pricing (2/2)

Ameren offers an equivalent Power Smart Pricing Program

- In 2018, 79% of the Power Smart Pricing's 13,339 active participants saw savings compared to what they would have paid under Ameren's standard fixed-price rate. Customers saved an average of $58 (8%)

Both programs are mandated by Illinois' Public Utilities Act, and overseen by the Illinois Commerce Commission

References:

Ameren, Power Smart Pricing 2018 Report, https://www.icc.illinois.gov/docket/files.aspx?no=11-0547&docId=285537

Oklahoma
Variable Peak Pricing

OGE rolled out a dynamic pricing rate coupled with a smart thermostat to its residential customers a few years ago

- "Smart Hours" features variable peak pricing, or four levels of peak pricing depending on what day type it happens to be (Low, Standard, High, Critical)
- There are fixed summer and winter peak hours
- The expectation is that there would be 10 Low price days, 30 Standard price days, 36 High price days, and 10 Critical price days in a typical year.
- Prices during peak hours vary depending on system conditions, and are communicated by 5:00 pm the previous day. Critical periods can be communicated with as little as two hours notice
- Is also offered to Small GS customers whose annual demand is less than 10 kW or less than 400 kW with a load factor of less than 25%

Some 130,000 customers out of 650,000 (20%) are on that rate today; they control their thermostat setting, not OGE

- Average peak load has dropped by ~40%
- Average bill savings amount to ~20% of the customer's bill

References:

Oklahoma Gas & Electric, SmartHours, https://www.oge.com/wps/portal/oge/save-energy/smarthours/faq/

New York
Time-of-Use Rates

Consolidated Edison (Con Edison), which serves 3.4 million customers in New York City's five boroughs and Westchester County, employs a standard residential delivery rate consisting of a fixed charge and a variable charge

- For June through September, the variable charge is a two-tiered inclining block rate, while it is a flat volumetric charge in all other months

Con Edison also offers a voluntary delivery TOU rate with a peak period of 8 AM to midnight

- The TOU rate's delivery rates reflect a 14:1 peak/off-peak ratio from June through September and a 5:1 ratio in all other months
  - The rate also has a year-round monthly customer charge of $20.46 (vs. $16 under the standard rate)

Con Edison also offer super-peak pricing for supply (in effect 2-6 PM on summer weekdays), but does not apply to customers who purchase their electricity from energy service companies

References:

Con Edison, Current Electricity Tariffs, https://www.coned.com/_external/cerates/documents/elecPSC10/electric-tariff.pdf

Con Edison, Time-of-Use Rates, https://www.coned.com/en/save-money/energy-saving-programs/time-of-use

New York
Time-Varying Demand Charges

Con Edison is also conducting a three-year Smart Energy Plan pilot program with time-varying demand charges for delivery service

- During the peak period (noon to 8 PM weekdays), the demand charge is $19.66/kW in the summer and $15.13/kW in the winter, compared to $7.64/kW in the year-round off-peak period
- Around 15,000 customers were initially recruited into the program, using both opt-in and opt-out enrollment, with the option to opt out of the program at any time
  - Con Edison's AMI rollout is ongoing and expected to be completed by the end of 2022. Pilot participants were selected from regions with high AMI penetration.
  - Customers that have smart meters but were not recruited for the pilot can currently still enroll on a "walk-in" basis
- Con Edison is also testing another demand rate with a peak period of 2-10 PM weekdays and a slight difference in prices

References:

Con Edison, Introducing the Smart Energy Plan, https://www.coned.com/en/accounts-billing/smart-energy-plan

Con Edison, Innovative Pricing Pilot Filing, https://www.coned.com/_external/cerates/documents/elec/pending/innovative-pricing-pilot-filing.pdf

Utilities across the globe are also experimenting with multiple pricing options

Since 2014, Spain has offered real-time pricing as the regulated default rate for residential customers, with approximately 40% of customers currently enrolled

In Italy, TOU rates have been mandatory since 2010 for all low-voltage residential customers

- A 1.5 year transitional phase included limited variation between the peak and off-peak prices, before expanding to a larger price difference for the final tariff

In the United Kingdom, Green Energy UK offers a time-varying TIDE tariff, while in 2018 Octopus Energy tested the first half-hourly TOU tariff and found that customers shifted usage out of peak periods by 28%

References:

REE, Voluntary price for the smaller consumer, https://www.ree.es/en/activities/operation-of-the-electricity-systemvoluntary-price-small-consumer-pvpc

Maggiore et. al., Evaluation of the effects of a tariff change on the Italian residential customers subject to a mandatory time-of-use tariff, https://www.eceee.org/library/conference_proceedings/eceee_Summer_Studies/2013/7-monitoring-and-evaluation/evaluation-of-the-effects-of-a-tariff-change-on-the-italian-residential-customers-subject-to-a-mandatory-time-of-use-tariff/

Octopus Energy, Agile Octopus: paving the way to a low carbon future, https://octopus.energy/static/consumer/documents/agile-report.pdf

Green Energy UK, A new and better way to control home energy bills, https://www.greenenergyuk.com/PressRelease.aspx?PRESS_RELEASE_ID=76

Ontario
Time-of-Use Rates (1/2)

The Ontario Energy Board mandated the installation of smart meters for all customers to promote a culture of conservation. The C$ 2 billion rollout of 4.7 million smart meters was complete by 2014

Alongside smart meters, Ontario introduced default TOU rates in 2011-12 for residential and small commercial customers

- Some 90% of Ontario's 4 million residential customers have been buying their energy through a regulated supply option, which features a three-period TOU rate
- The TOU rates only apply to the energy portion of the customer's bill
- Off-peak, mid-peak, and on-peak prices are defined by season
- A small number of customers without smart meters are on Tiered Pricing rates with seasonally differentiated tiers and prices
- Large commercial and industrial customers pay wholesale prices

Due to Covid-19 pandemic, the Government of Ontario announced that TOU customers will pay volumetric rates from June 1 to October 31, 2020

References:

Ontario Energy Board, Electricity Rates, https://www.oeb.ca/rates-and-your-bill/electricity-rates

Ontario
Time-of-Use Rates (2/2)

A Brattle analysis of the TOU rates from their inception in 2009 through 2014 found that for the Province as a whole, TOU reduced usage during the summer peak by 3.3% in the pre-2012 period, 2.3% in 2012, 2.0% in 2013 and 1.2% in 2014

- Local distribution companies (LDCs) gradually adopted TOU rates beginning in 2009, and were all on TOU by 2012
- Load shifting impacts were lower in winter, which similar to the summer impacts decreased over successive years of the study
  - The peak/off-peak price ratio for all of LDCs throughout the analysis period was approximately 1.5
- No evidence of electricity conservation was observed

References:

Lessem, N., A. Faruqui, S. Sergici, and D. Mountain, "The Impact of Time-of-Use Rates in Ontario," *Public Utilities Fortnightly* (Feb. 2017)

British Columbia
Time-of-Use Pilots

BC Hydro, which serves approximately 95% of British Columbia's 4.6 million residents, conducted a pilot from 2006-2008 testing TOU and TOU/CPP rates for approximately 2,000 opt-in customers

- BC Hydro's residential energy charge currently includes an inclining block structure, but at the time was simply a flat rate
- To avoid adverse selection, BC Hydro randomly assigned participants into either a control group, or a treatment group facing five different TOU rate schedules
  - In summer, the treatment group was billed at the regular residential rates (as was the control group)
  - In winter, the TOU rates had peak/off-peak price ratios of 3.6, while the CPP/TOU rate had a peak/off-peak ratio of 7.9 for CPP and 3 for TOU
- At the time, BC Hydro staff found that over the pilot's first winter, the treatment group reduced their peak usage by 9.6%, and that the availability of an in-home display (IHD) did not have a discernible effect
  - However, a more recent regression analysis based on the pilot's second winter of operation estimated that IHD would approximately double TOU reductions of 2.2%-4.4% without IHD, and critical peak reductions of 4.8%-5.3% without IHD

References:

Woo, C.K., J. Zarnikau, A. Shiu, R. Li, "Winter Residential Optional Dynamic Pricing: British Columbia, Canada", *The Energy Journal* 38:5 (2017)

Quebec
Dynamic Pricing (1/2)

From December 2008 to March 2010, Hydro-Québec (HQ) conducted a "Time it Right" pilot with 2,200 households in four cities

- The pilot tested two rate designs, Réso (TOU) and Réso + (TOU/CPP), summarized below

	Réso				Réso+			
	Winter		Summer		Winter		Summer	
(CAD c/kWh)	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
First 15 kWh per day	6.57	4.34	6.15	4.65	6.15	3.60	6.15	4.65
Additional kWh	8.63	6.40	8.19	6.69	8.19	5.63	8.19	6.69
Critical peak usage	-	-	-	-	18.19	-	-	-

Notes: Winter is defined as December through March, and summer as April through November. Peak hours are from 6 AM – 10 PM under Réso, and 7-11 AM and 5-9 PM under Réso +. The default fixed charge of 40.46 c/day applied under both experimental rates.

  - Under Réso, peak period usage reductions were not statistically significant
  - Under Réso+, 28 critical days were called, with a statistically significant average reduction of approximately 6% (0.27 kW) in critical peak events over the two winters

- ~88% of participants stayed on the experimental rates through the end of the pilot

References:

Hydro-Quebec, Rapport final du Projet Tarifaire Heure Juste, http://www.regie-energie.qc.ca/audiences/3740-10/Demande3740-10/B-1_HQD-12Doc6_3740_02aout10.pdf

Quebec
Dynamic Pricing (2/2)

In April 2019, Hydro-Québec began gradually rolling out opt-in residential PTR and CPP rate offerings for a limited number of customers

- Randomly selected customers were invited to sign up for one of the two dynamic pricing rates, with sign ups reaching the maximum limit for winter 2019-2020
- The *Winter Credit Option (PTR)* offers a 50 c/kWh peak time rebate for reducing electricity during winter peak demand events
  - The fixed charge and two-tiered variable charge for all other hours are the same as under the default residential rate, which charges 4.28 c/kWh for energy consumed up to 40 kWh a day, and 7.36 c/kWh for all other usage
- The *Rate Flex D (CPP)* rate charges a higher rate of 50 c/kWh for energy consumed during winter peak demand events
  - In summer, the fixed charge and two-tiered variable charge for all other hours are the same as under the default residential rate
  - In winter, the variable charge includes savings of 22%-30% depending on the tier on non-event days
- There may be 25-33 events per winter, at most, for a maximum of 100 hours in all

References:

Hydro-Québec, Dynamic pricing, http://www.hydroquebec.com/residential/customer-space/rates/dynamic-pricing.html
Hydro-Québec, Electricity Rates effective April 1, 2019, http://www.hydroquebec.com/data/documents-donnees/pdf/electricity-rates.pdf

Australia
Time-of-Use Rates

SA Power Networks (SAPN), which serves around 1.7 million customers in South Australia, has recently proposed offering default TOU rates for residential customers with interval meters starting in July 2020

- Around 20% of residential and small business customers currently have interval meters, with that number expected to grow to 50% by 2025
- These rates will include a "solar sponge" component with a super off-peak period of 10 AM – 3 PM when solar exports are high, an off-peak period of 1-6 AM, and a peak period consisting of all other hours
  - The "solar sponge" rate is 25% of the standard rate; off-peak prices are 50% of the standard rate and peak period rate is 125% of the standard rate
- This is designed to respond to a change in the residential daily profile caused by an increase in solar PV adoption, which has caused a pattern of load peaks and troughs and shifted peak demand
  - Over 30% of customers have now installed solar on their rooftops

References:

SAPN, Attachment 17, Tariff Structure Statement Part B – Explanatory Statement, December 2019, https://www.aer.gov.au/system/files/SAPN%20-%20Revised%20Proposal%20-%20Attachment%2017%20-%20Tariff%20Structure%20Statement%20Part%20B%20-%20Explanatory%20Statement%20-%20December%202019_0.pdf

Note that the Australian Energy Regulatory approved these proposed rate structures in a draft decision to be effective in July 2020. However, the final decision is expected in April 2020.

Australia
Three-Part Rates with TOU

SAPN is also proposing to offer an optional, three-part "Prosumer" tariff for customers with interval meters

- The monthly demand charge is estimated using average demand over a four-hour period from 5-9 PM for November through March
- The TOU rates under the Prosumer tariff will be halved relative to those under the default TOU rate
- This rate structure accommodates customers who want to discharge energy storage systems during peak periods
- SAPN analysis finds that the standard deviation in customer outcomes (i.e., bill impact) is significantly larger under the Prosumer tariff than with TOU

References:

SAPN, Attachment 17, Tariff Structure Statement Part B – Explanatory Statement, December 2019, https://www.aer.gov.au/system/files/SAPN%20-%20Revised%20Proposal%20-%20Attachment%2017%20-%20Tariff%20Structure%20Statement%20Part%20B%20-%20Explanatory%20Statement%20-%20December%202019_0.pdf

New Zealand
Peak Time Rebate Programs

Vector, the distribution utility that serves Auckland, the most populous city in New Zealand, conducted a PTR pilot program from June – August 2019 with 630 customers

- At the time, Vector served most residential customers on a two-part rate with a flat volumetric charge
- The peak time rebate was applied only to the distribution rate, with a peak to off-peak ratio of 5.4:1
- There were 7 event days with both a morning peak period (7-11 AM) and evening peak period (5-9 PM)
  - Event days were triggered by Vector staff when minimum peak temperature was expected to drop below 9 degrees
- The pilot was carried out jointly with a retailer, Mercury

References:

Confidential The Brattle Group analysis of Vector's winter 2019 pilot

New Zealand
Time-of-Use Rates

In April 2020, Vector Limited expects to restructure its flat distribution charge as a TOU charge for Residential and General Consumer customers

- The TOU rates have a peak period of 7-11 AM and 5-9 PM weekdays, and a peak/off-peak ratio of approximately 2.5:1 for Low User customers and 5:1 for Standard customers
  - The Low User tariff represents a low fixed-charge option to assist low-use customers

It will be up to the retailers whether to pass through these TOU delivery charges to retail customers or to bundle them into some other types of charges

References and Notes:

Vector Limited, Electricity prices effective from 1 April 2020, https://www.vector.co.nz/personal/electricity/pricing/electricity-prices-2020

US Benchmark
Overview of *Commercial* TVP Offerings

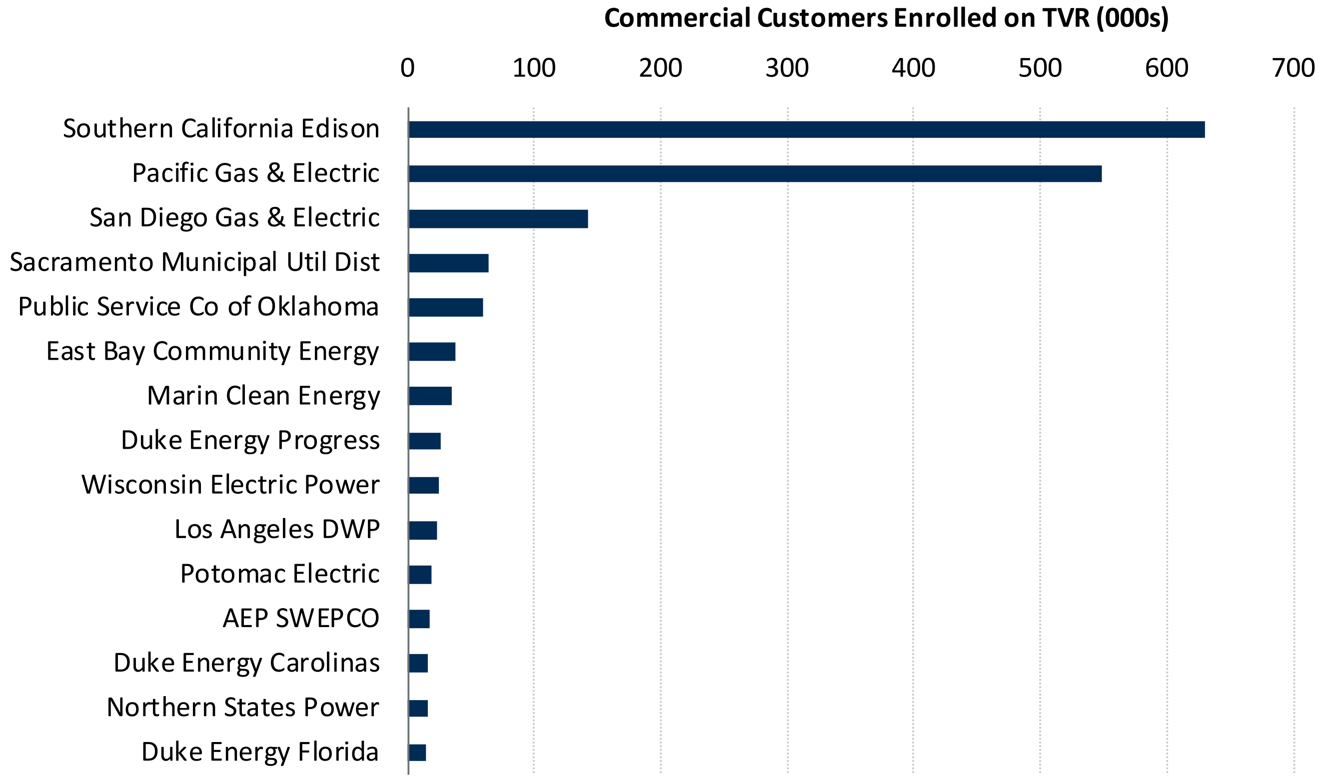
According to 2018 EIA Form-861, **463 U.S. utilities offer at least one TVP to their commercial customers**

- 401 offer Time-of-Use (TOU)
- 57 offer Real-Time Pricing (RTP)
- 49 offer Critical Peak Pricing (CPP)
- 16 offer Peak Time Rebate (PTR)
- 18 offer Variable Peak Pricing (VPP)

Altogether, **approximately 2 million customers** (16% of commercial customers served by these utilities, or 9% of all commercial customers) are enrolled on one of these commercial TVPs

US Benchmark
Overview of *Commercial* TVP Offerings

The list of utilities with the most commercial customers on TVPs is dominated by California's utilities, which account for 77% of all commercial customers on TVPs. The three investor-owned utilities (SCE, PG&E, SDG&E) alone account for 68% of such customers.



US Benchmark

Overview of *Industrial* TVR Offerings

According to 2018 EIA Form-861, **447 U.S. utilities offer at least one TVR to industrial customers**

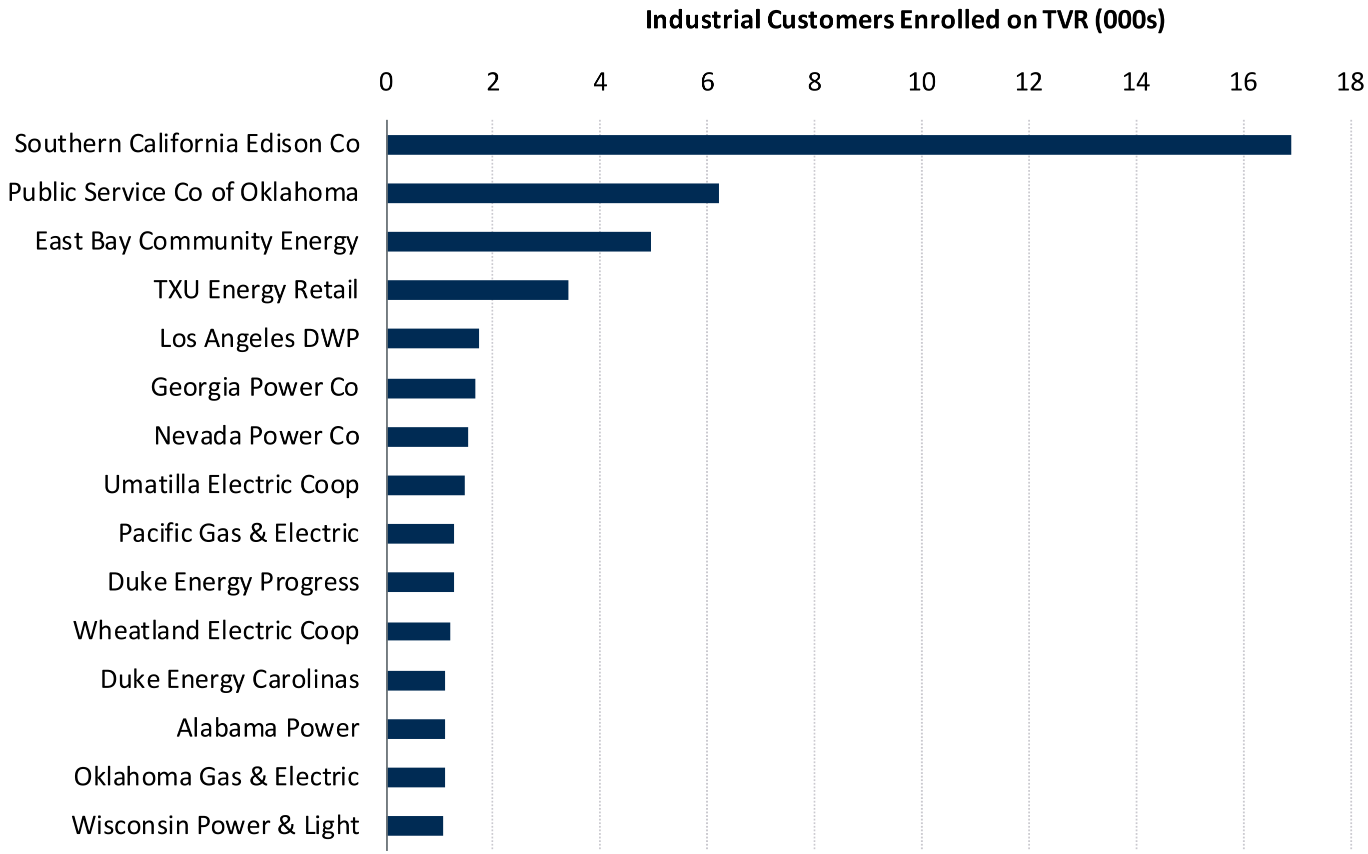
- 385 offer Time-of-Use (TOU)
- 67 offer Real-Time Pricing (RTP)
- 54 offer Critical Peak Pricing (CPP)
- 19 offer Peak Time Rebate (PTR)
- 11 offer Variable Peak Pricing (VPP)

As with commercial customers, RTP is the second most commonly offered TVP to industrial customers after TOU

Altogether, **approximately 65,000 customers** (14% of industrial customers served by these utilities, or 7% of all industrial customers) are enrolled on one of these industrial TVPs

US Benchmark
Overview of *Industrial* TVP Offerings

The top fifteen utilities account for 71% of all industrial customers on TVPs



Note: The CPUC currently requires all commercial and industrial customers be on time-of-use plans. However, the EIA data shows that only 1% of PG&E's 91,683 industrial customers are on a TVP, which may reflect a data reporting issue.

California IOUs
Non-Residential CPP Program

The three California IOUs (PG&E, SCE, and SDG&E) each operate non-residential CPP programs, under which customers are notified a day in advance of high-priced peak events

- SDG&E defaulted its large C&I customers to CPP rates in 2008, and PG&E and SCE in 2010. SDG&E and SCE have also defaulted small and medium business customers to CPP, while PG&E plans to complete its transition in 2020
  - Newly enrolled customers receive 12 months of bill protection
  - Most large customers can pay a fixed monthly Capacity Reservation charge to protect a certain level of kWh generation from CPP event days, though SCE eliminated this option in 2019
- PG&E and SDG&E's events last from 2-6 PM, while SCE recently shifted event hours to 4-9 PM to align with the resource adequacy window
- In Program Year (PY) 2019, SCE called 12 events, PG&E called 9, and SDG&E called none, with events each taking place on a June through October weekday
- PG&E and SCE reported 14.3 MW (1.2%) and 4.9 MW (0.3%) load impacts respectively
  - More than 99% of the total load impacts came from Large (>= 200 kW) customers, who make up <1% of enrolled customers

References: AEG, "2019 Statewide Load Impact Evaluation of California Non-Residential Critical Peak Pricing Programs," March 18, 2020

California IOUs

Base Interruptible Programs

PG&E, SCE, and SDG&E also operate voluntary Base Interruptible Programs, under which customers and aggregators receive a monthly capacity bill credit for committing to reduce their energy consumption to their Firm Service Level ("FSL", the level meeting their minimum operational requirements)

- Depending on the utility, participants are notified 15-30 minutes prior to an event, which can occur in any month and last up to 4-6 hours
- In 2019, PG&E had 480 enrolled participants, SCE had 484, and SDG&E had 5
  - Based on CPUC direction, SDG&E is instead focusing marketing on price responsive programs
- Each utility called at least one full event, which according to regression analysis by CA Energy Consulting yielded substantial load impacts:
  - *PG&E:* 173 MW (69% of enrolled load, or 99% of the reduction required to meet aggregate FSL)
  - *SCE:* 538 MW (79% of enrolled load, or 90% of the reduction required to meet aggregate FSL)
  - *SDG&E:* 2.9 MW (85% of enrolled load, or 96% of the reduction required to meet aggregate FSL)

References: Christensen Associates Energy Consulting, "2019 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers," March 16, 2020

Georgia Power
Real-Time Pricing Rates (1/4)

Roughly 15,000 customers are enrolled in Georgia Power's Real Time Pricing Rates (initially introduced as an economic development rate), which are offered at both an hour and day ahead level

Tariff	Eligibility	Main Features	Other Considerations
Real Time Pricing - Day Ahead *("RTP-DA-5")*	• Available to customers with peak 30-minute demand not less than 250 kW • For customers who can benefit from hourly price signals	• Customer and utility agree upon baseline usage, which is used to establish standard monthly bill • Customer is billed (or credited) for difference between baseline usage and actual usage at real-time prices, in addition to standard monthly bill • Real-time prices are calculated each day based on projections of supplying power	• RTP seeks to be revenue neutral • Price calculations consider: hourly cost of running incremental generation, provisions for losses, projections of transmission and capacity costs, and a cost recovery factor.
Real Time Pricing - Day Ahead with adjustable Customer Baseline Load *("RTP-DAA-6")*	• Available only to existing RTP-Day Ahead customers • For customers who can benefit from temporary price stability due to an expected increase in usage	• Offers temporary price stability for one calendar year, by allowing customer and utility to agree to raise their baseline load • Customer is billed (or credited) for difference between adjusted baseline usage and actual usage at real-time prices, in addition to standard monthly bill • Real-time prices are calculated each day based on projections of supplying power	• Customers that anticipate a significant increase in usage (e.g., from a planned expansion), might want to adjust their baseline load to expose less of their expected load to real-time prices

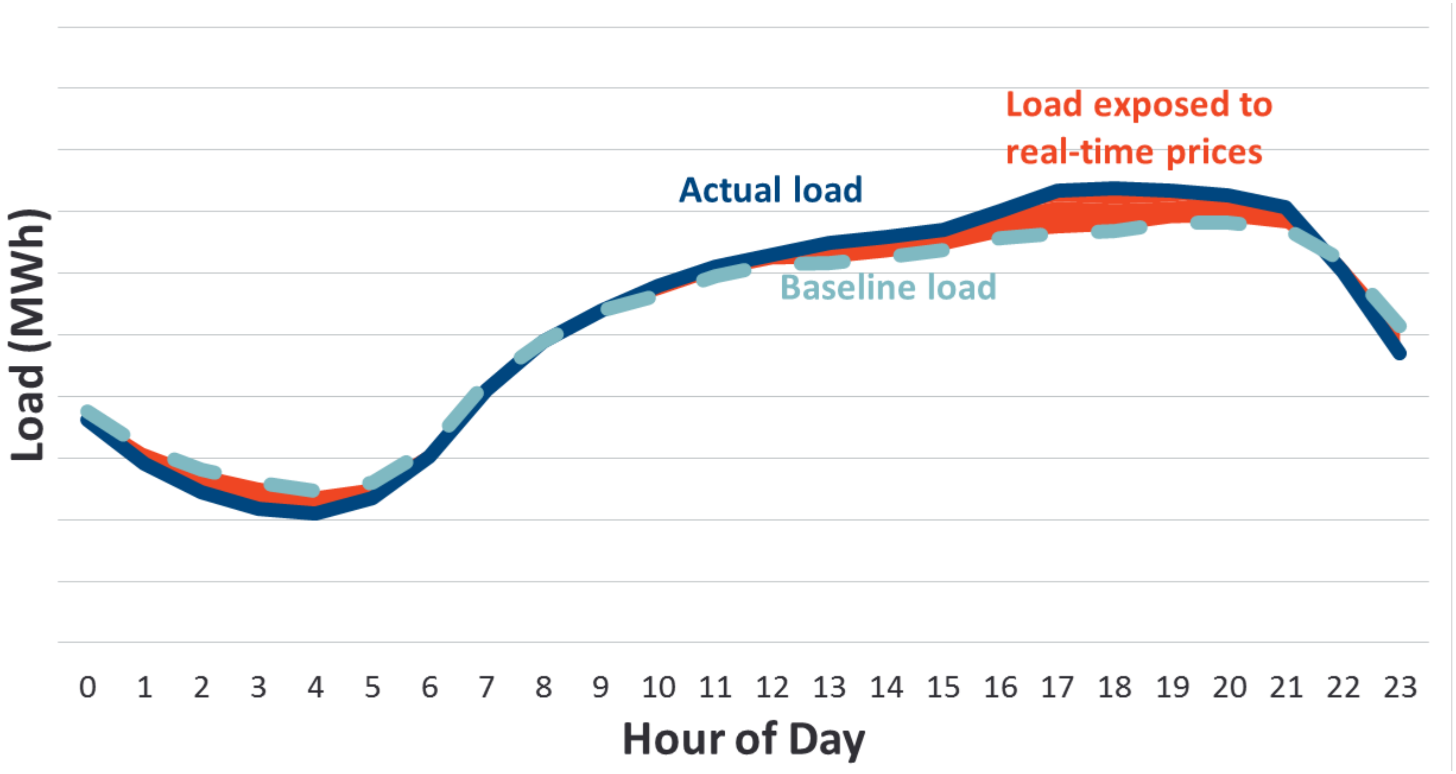
Georgia Power
Real-Time Pricing Rates (2/4)

Tariff	Eligibility	Main Features	Other Considerations
Real Time Pricing - Hour Ahead *("RTP-HA-5")*	• Available to customers with peak 30-minute demand not less than 5,000 kW • For customers who can benefit from hourly price signals that are furnished 60 minutes in advance	• Customers are notified of day-ahead hourly prices, which are then updated 60 minutes before becoming effective • Baseline load and bills are calculated with same approach as RTP - Day Ahead approach.	N/A
Real Time Pricing - Hour Ahead with adjustable Customer Baseline Load *("RTP-HAA-6")*	• Available only to existing RTP-Hour Ahead customers • For customers who can benefit from temporary price stability	• Customers are notified of day-ahead hourly prices, which are then updated 60 minutes before becoming effective • Baseline load and bills are calculated with same approach as RTP - Day Ahead with adjustable Customer Baseline Load approach.	N/A

References: Georgia Power, Business Rates, Marginally Priced Rates, https://www.georgiapower.com/business/billing-and-rates/business-rates.html

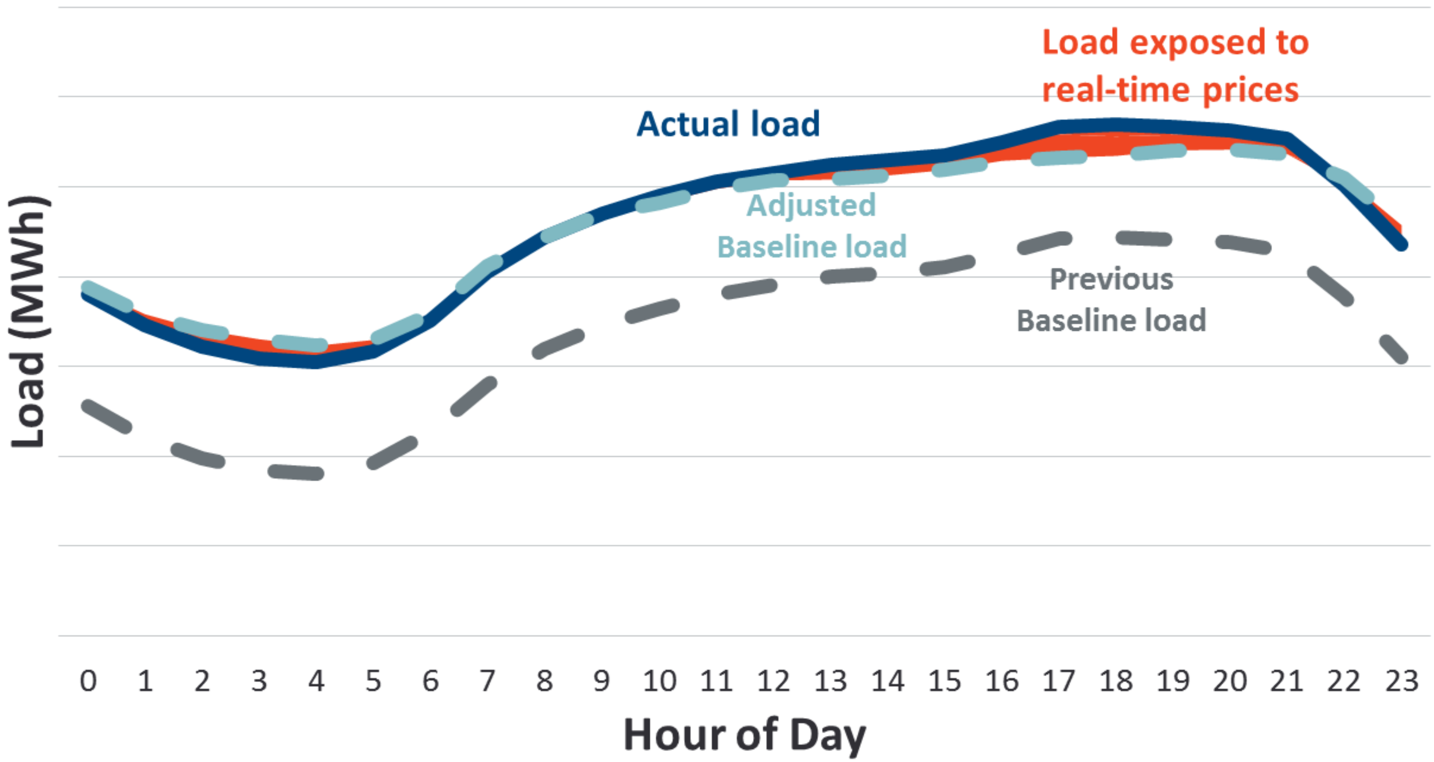
Georgia Power
Real-Time Pricing Rates (3/4)

With a real-time pricing rate, the customer is billed (or credited) for differences between actual load and established "baseline" load at real-time prices



Georgia Power
Real-Time Pricing Rates (4/4)

Customers may work with the utility to update their baseline load shapes, if the customer has been on RTP for over a year and is anticipating a significant change in load



Lessons Learned from Time-Varying Rate Deployments I

Utilities have long deployed time-varying rates, some more successfully than others. Following are key lessons learned during the past two decades of deployment

1	**Designing the rates**	• Rates should be cost-reflective to promote economic efficiency and equity. However, they should also be **customer focused** • Unless new rates have **savings opportunities**, customers will either not join or not alter their usage habits to respond. Savings opportunities can be maximized by discounting off-peak prices substantially compared to the existing rate	**Implications for NS Power TVP Programs** • Requires assessment of NS Power near-term and longer-term embedded and marginal costs and assessment of Company's long-term capacity requirement outlook. Ongoing IRP is key to providing this • To avoid cost transfer and to match system savings with costs a Lost Revenue Adjustment Mechanism likely to be required

Lessons Learned from Time-Varying Rate Deployments II

2	Marketing the rates	• Most utilities offer time-varying rates but only a handful of customers are on them. Often, customers don't even know the rates exist due to limited **customer outreach and advertising** • Customers who know the rates exist have questions, but customer service staff are untrained to answer them while information on websites is poorly presented and couched in utility-speak that eludes customers • This can be remedied by studying customer service practices of utilities like APS and OGE, which have large numbers of customers on time-varying rates • Utilities can also conduct **focus groups** with customers to get insights on which design features appeal to customers and which ones turn them off. For further insights, **conjoint analysis** can be carried out with data gathered via online customer surveys	**Implications for NS Power TVP Programs** • With the ongoing transformation of the Company's generation portfolio and proliferation of Smart Grid and Distributed Energy Resources, it is likely there will be an increased role for TVP in NS over the next decade • Though the Company has experience with TVP in Residential and Large Industrial customer classes, limited general awareness across the customer population means the implementation of these requires deliberate and extensive customer engagement

Lessons Learned from Time-Varying Rate Deployments

3	**Inclusion of enabling technologies**	• Customer responses to time-varying rates can be facilitated and often magnified by including new **digital thermostats** rapidly being acquired by customers. For example, OGE has successfully used smart thermostats to boost response and take the pain out of demand management • Other enabling technologies include **digitally-enabled appliances and home-energy controllers**	**Implications for NS Power TVP Programs** • NS Power's experience with the residential TOD Tariff can be leveraged in the new TVP offerings • Recent/pending programs including the Intelligent Feeder Program and Smart Grid Project and work with E1 re: Demand Response provide opportunities to build on this experience and establish processes for future equipment/TVP pairings

Lessons Learned from Time-Varying Rate Deployments

4	**Inclusion of behavioral messaging**	• Research has shown that **behavioral messaging** or **social norming** can boost response • This can be done through mailers, emails and text messages, which inform customers of how their change in usage compares with the response of peers on the same rate	**Implications for NS Power TVP Programs** • The information development and customer engagement enabled by AMI means more sophisticated and economic TVP programs are possible. • However the Company remains in the early days of AMI roll-out and time is required to develop analytics and processes regarding engagement with customers employing the AMI data such that customers can have confidence they will realize savings from the TVP programs offered

References: See Faruqui, Ahmad and Dr. Stephen S. George, "Demise of PSE's TOU program imparts lessons," *EL&P* (Jan. 2003), https://www.power-grid.com/2003/01/01/demise-of-pses-tou-program-imparts-lessons/

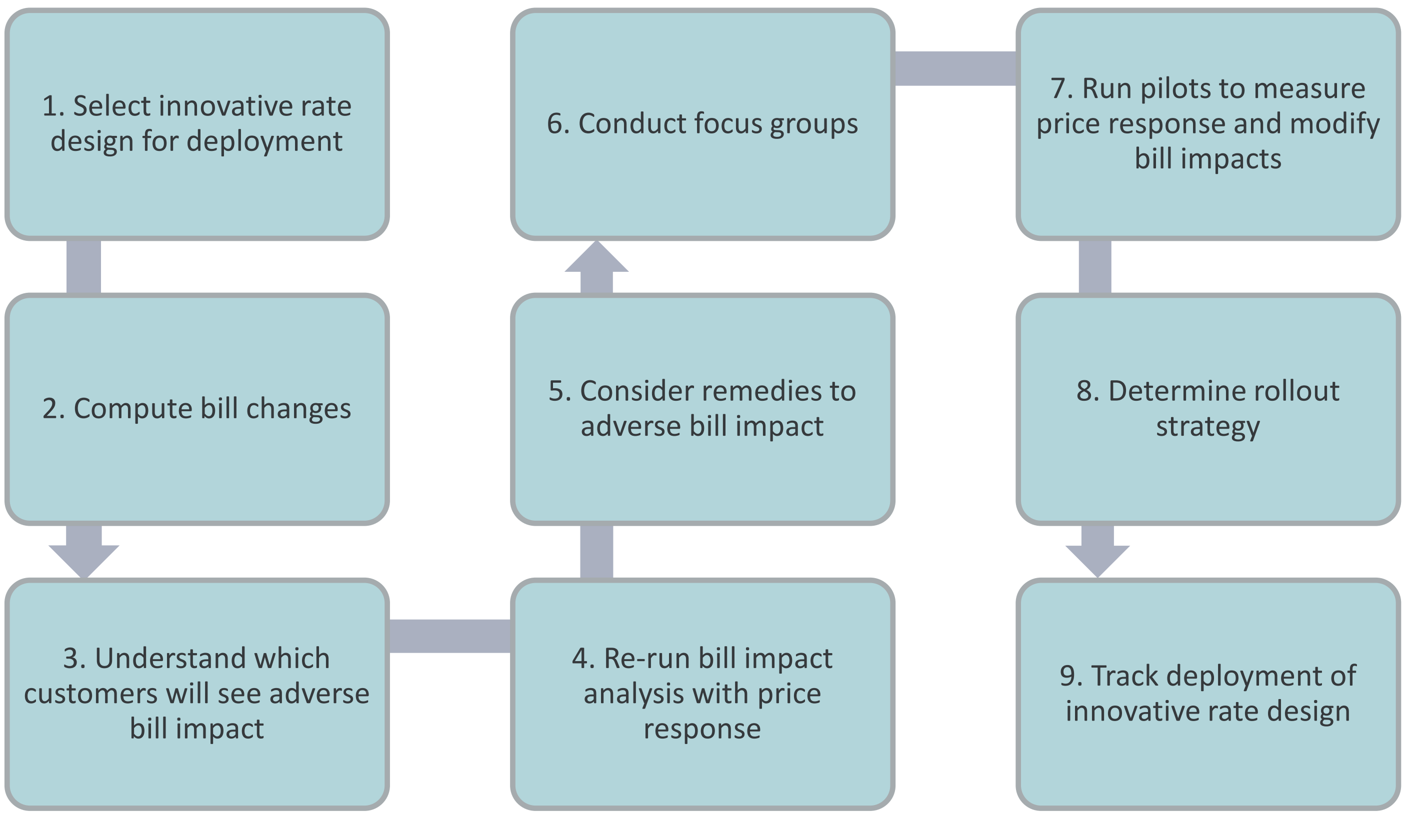
Lessons Learned from Time-Varying Rate Deployments

5	**Transitioning to new rates**	• Many rollouts are abruptly handled, such that **customers are not prepared** for the arrival of the new rates, and customer service staff are not trained to answer customer questions • This can be avoided through **proper planning**	**Implications for NS Power TVP Programs** • NS Power requires a TVP Strategy that aligns TVP development and implementation with NS Power AMI deployment, industry developments and continued generation transformation for the benefit of all customers • The Strategy should be underpinned by Company resource planning developments (i.e. IRP) and emerging opportunities/initiatives (e.g. Smart Grid project, electrification) • Key to the strategy will be disciplined and transparent customer engagement processes that utilize the AMI data • The Strategy will support ongoing refinement of TVP programs

References: See Faruqui, Ahmad and Dr. Stephen S. George, "Demise of PSE's TOU program imparts lessons," *EL&P* (Jan. 2003), https://www.power-grid.com/2003/01/01/demise-of-pses-tou-program-imparts-lessons/

Transitioning to the new rates

The pathway below lays out steps worth considering when transitioning customers to new rates



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Overview of Time Varying Price Design Considerations

RECOMMENDATIONS FOR NOVA SCOTIA POWER

PRESENTED TO

NS Power

PRESENTED BY

Ahmad Faruqui, Ph.D.
Sanem Sergici, Ph.D.

June 2020

THE Brattle GROUP

Rate designs are evaluated with respect to well known rate design principles

Principles	Objective
1. Cost causation	• Rates should reflect cost causation, including embedded costs, long-run marginal and future costs, and the fixed cost nature of delivering electricity
2. Encourage efficient outcomes	• Rates should encourage economically efficient and market-enabled decision-making, for both efficient use of the grid by customers and new investments
3. Fair Value	• Customers and utility should both be paid the fair value for the grid services they provide
4. Customer Orientation	• Rates should aspire for simplicity while providing customer choices
5. Stability	• Customer bills should be relatively stable
6. Access	• Electricity should remain affordable and accessible for vulnerable sub populations
7. Gradualism	• Rate changes should be implemented in a manner which would not cause any large bill impacts
8. Economic Sustainability	• Rate design should reflect a long-term approach to price signals, remain neutral to any particular technology or business cycle and avoid cross-subsidies and prevent abuse/gaming/arbitrage

Source: Bonbright Principles adapted based on “NYREV Order Adopting A Ratemaking and Utility Revenue Model Policy Framework,” May 2016.

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AMI enables a variety of modern rates, including TVPs

Rate	Definition
1- Time-of-Use *(TOU)*	The day is divided into peak and off-peak time periods. Prices are higher during the peak period hours to reflect the higher cost of supplying energy during that period
2- Critical Peak Pricing *(CPP)*	Customers pay higher prices during critical events when system costs are highest or when the power grid is severely stressed
3- Peak Time Rebates *(PTR)*	Customers are paid for load reductions on critical days, estimated relative to a forecast of what the customer would have otherwise consumed (their “baseline”)
4- Variable Peak Pricing *(VPP)*	During alternative peak days, customers pay a rate that varies by day to reflect dynamic variations in the cost of electricity
5- Real-Time Pricing *(RTP)*	Customers pay prices that vary by the hour to reflect the actual cost of electricity
6- Two-part Real-Time Pricing *(2-part RTP)*	Customer’s current rate applies to a baseline level of consumption. A second, marginal cost based, price applies to deviations from the baseline consumption
7- Three-part Rates *(3-part Rates)*	In addition to volumetric energy charge and fixed charge, customers are also charged based on peak demand, typically measured over a span of 15, 30, or 60 minutes
8- Fixed Bill with Incentives	Customers pay a fixed monthly bill accompanied with tools for lowering the bill (such as incentives for lowering peak usage)

Behavioral economics tells us that customers have diverse preferences

Market research studies and surveys undertaken in the context of time-based pricing pilots reveal valuable insights on customer preferences

Some want the lowest price

- They are willing to be flexible in the manner in which they use electricity

Some want to lock in a guaranteed bill

- They are willing to pay a premium for peace-of-mind

Many others are in between these two bookends

- Some might want a guaranteed bill but may be willing to lower it if rebates are offered for reducing demand during peak periods
- Others may wish to subscribe to a given level of demand

All customers want choice but *they only want what they want*

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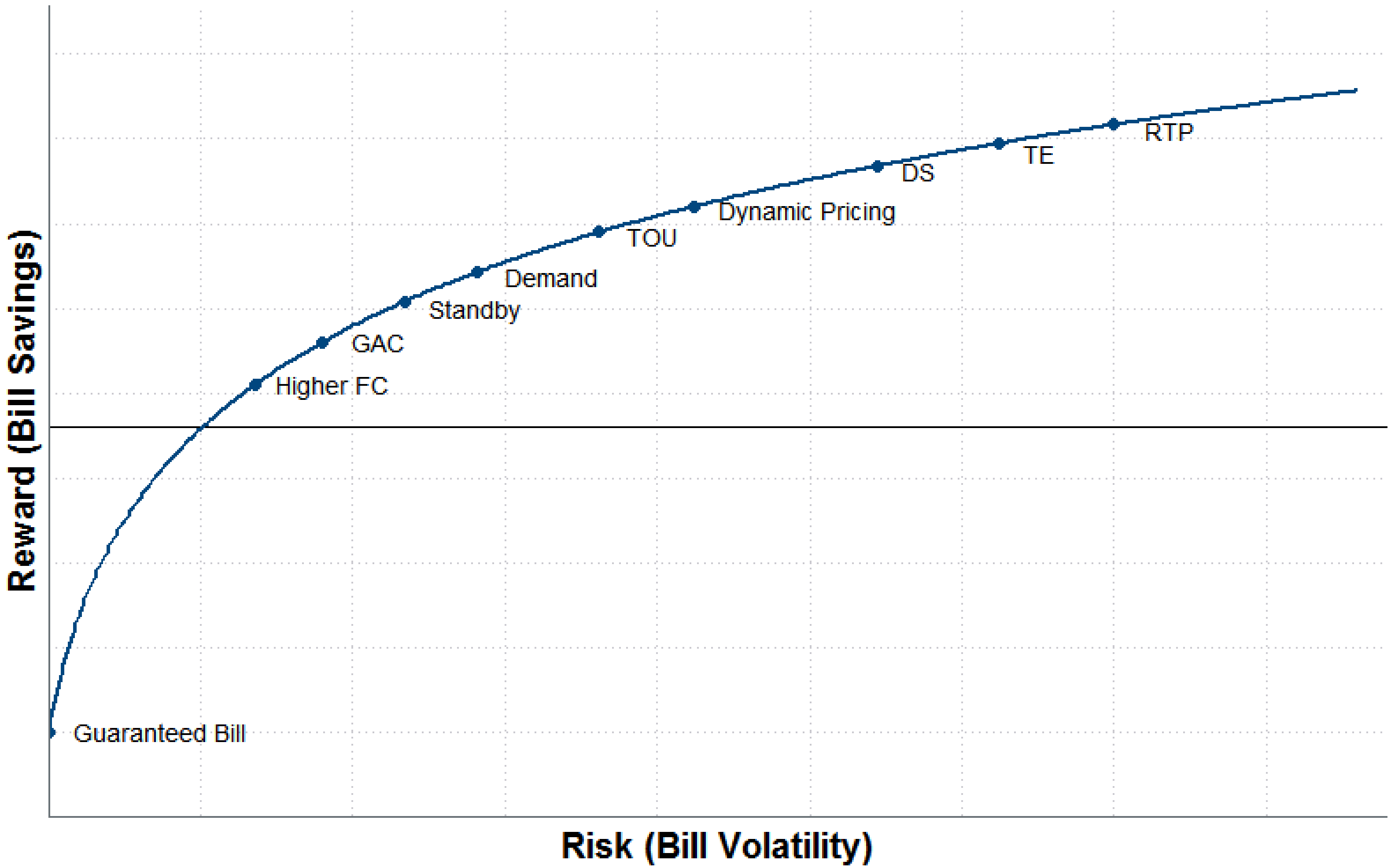
These create an efficient pricing frontier along which customers would be free to choose



NS Power Time Varying Pricing Strategy I

Our analyses indicate that offering CPP and TOU rates initially on an opt-in basis is a reasonable path forward

Based on the type of traction gained with customers over the next several years, one of these rates could be made default rate (at least for new customers and potentially for all residential customers)

Future rate development should consider the following guiding principles:

- Focus on programs with a high probability of success to build support for TVP in Nova Scotia
- Aligned with and support the Company's medium-long-term resource plan as informed by the current and future IRPs
- Aligned with Smart Grid developments and electrification opportunities as they arise

NS Power Time Varying Pricing Strategy II

As experience with AMI processes and customer awareness grows, more sophisticated TVP programs can be introduced (e.g. three part rates) and/or TVP can be paired with equipment deployment (e.g. water heaters, electric vehicles)

In advance of this, opportunities to **test and refine TVP programs through pilots and emerging opportunities** and innovation projects (e.g. the Smart Grid Project) should be pursued

As TVP programs are introduced, **regulatory mechanisms** (e.g. lost revenue deferrals) should be introduced to align the cost of these programs (e.g. lost revenue) with the future benefits to be realized (e.g. capacity savings) in order to avoid cost-shifting

Case for CPP

CPP rates yield to sizable peak reductions due to having higher peak to off-peak ratios

CPP belongs in the "dynamic" rate category as the event days are determined based on the system peak conditions

Question: Should the CPP rate be coupled with a TOU rate on non-CPP days in the peaking season?

Recommendation: initially offer CPP rate as a standalone rate to reduce complexity

CPP Rate Design Considerations

The design of the rate should balance system efficiency and cost savings with customer experience

- Number of event days and frequency of critical peak events should be carefully considered (8-12 days in a given season)
- CPP is typically designed to reflect long-run marginal cost of capacity to meet system peak and short-run marginal cost of energy during critical peak hours
- CPP should be sufficiently high to give customers meaningful incentives for load shifting (CPP/offpeak > 6)
- Customers should be given sufficient notice to plan their load shifting activities. However, the shorter the lead time, the demand reductions from the CPP becomes more valuable from a utility planning perspective

Case for TOU

TOU is the simplest and most widely used form of TVR throughout the world, and is already the default in Ontario

- It would make sense to offer a well-designed TOU rate with significant savings opportunities and a narrow peak period
- TOU could be combined with CPP, or offered as a standalone rate
- A more sharply differentiated TOU rate with a super off-peak period could be offered for EV owners

Question: Should the TOU rate be limited to the winter season to increase customer acceptance?

Recommendation: it is reasonable to offer TOU rates initially during the winter season as the peak reduction is mostly needed in the winter months

TOU Rate Design Considerations I

TOU is the simplest and most widely used form of TVP throughout the world

- It would make sense to offer a well-designed TOU rate with significant savings opportunities and a narrow peak period
- TOU could be offered along with CPP rates
- A more sharply differentiated TOU rate with a super off-peak period could be offered for EV owners
- Seasonal differences in load shapes and price differentials should be considered in designing the rates
- Simplicity of the design is key in increasing the uptake
- Behavioral messaging, smart thermostats and bill impact tools can accompany the rates to enhance comprehension and responsiveness

TOU Rate Design Considerations II

- Keep the peak period short
- Refrain from multiple periods, especially split mid-peak periods unless there is a good basis
- Undertake billing analysis
- In determining the peak period, consider the change in load shape due to solar penetration
- Target a peak/offpeak ratio > 3 for sizable impacts although jurisdictional circumstances may affect the outcomes
- Educate customers on ways to change behavior; offer bill impact analyses
- TOU rates are not very useful for addressing specific events on the grid and integrating variable renewable energy resources. Consider event-based rates such as CPP rates to address those concerns
- EV TOU rates would involve different design considerations

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Case for Piloting Three-Part Rates

Three-part rates are emerging as the favorite rate design for many utilities, who argue that they should be offered to all classes of customers with the appropriate metering

- Since demand charges have not yet been offered to residential customers in Nova Scotia, it might make sense to first test the three-part rate through a well-designed pilot program
- It would be useful to include a TOU element for the energy charge component, as well as potentially also for the demand charge component (e.g., as is being done for Con Edison in New York)

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Development of Time Varying Pricing Periods

ANALYSIS OF LOAD AND PRICE DATA

PRESENTED TO
NS Power

PRESENTED BY
Ahmad Faruqui, Ph.D.
Sanem Sergici, Ph.D.

June 2020

THE Brattle GROUP

There are several steps involved in designing time of use rates

Step 1: Collect data

Step 2: Analyze data to identify pricing seasons and periods

Step 3: Set rates

Step 4: Estimate load and bill impacts of the new rates

Step 5: Adjust rates if necessary

Step 6: Finalize rates

In this slide deck, we describe our approach to the first two steps

We first assisted Nova Scotia Power in the determination of peak windows

We analyzed Nova Scotia Power hourly load and marginal cost data (2018 and 2019) to identify potential pricing seasons and peak windows

The definition of pricing seasons and peak and off-peak windows is an important element of the TOU rate design

An ideal peak window has the following attributes:

- Captures the high load and/or high marginal cost hours
- Captures seasonal differences to the extent that there are noticeable changes across the year
- Provides a reasonable opportunity to change behavior; not too short (<4) or too long (>6)

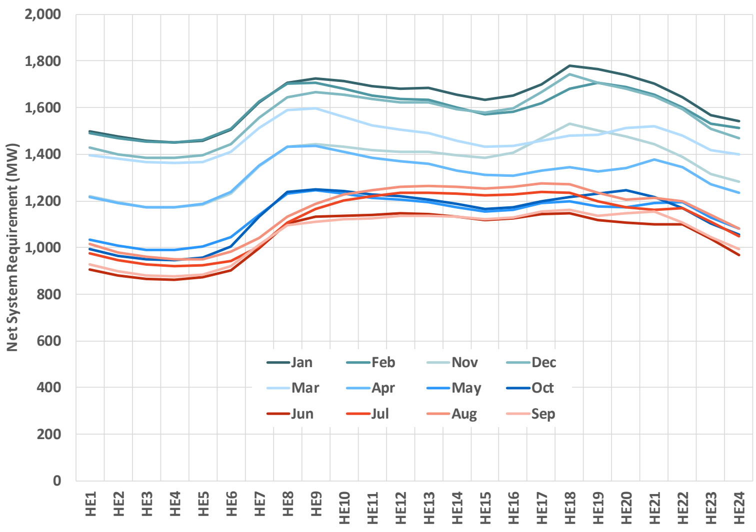
To identify peak windows throughout the year, we examined seasonality in system load

Based on NS Power's typical weekday net system requirement profile from 2018 and 2019, we observed three distinct seasonal patterns:

- Winter: **January, February, November, and December** feature bimodal peaks, with a *more pronounced evening peak*
- Summer: **June through September** features mostly flat load during daytime
- Spring & Fall: **March, April, May, and October** feature bimodal peaks, with a *more pronounced morning peak*

NS Power adopted these seasonal definitions in designing its proposed TVP rates, with the exception of alternative specifications that include March in winter

2018 – 2019 Typical Weekday System Load Profile by Month



Next, we determined pricing windows by season through **cluster analysis**

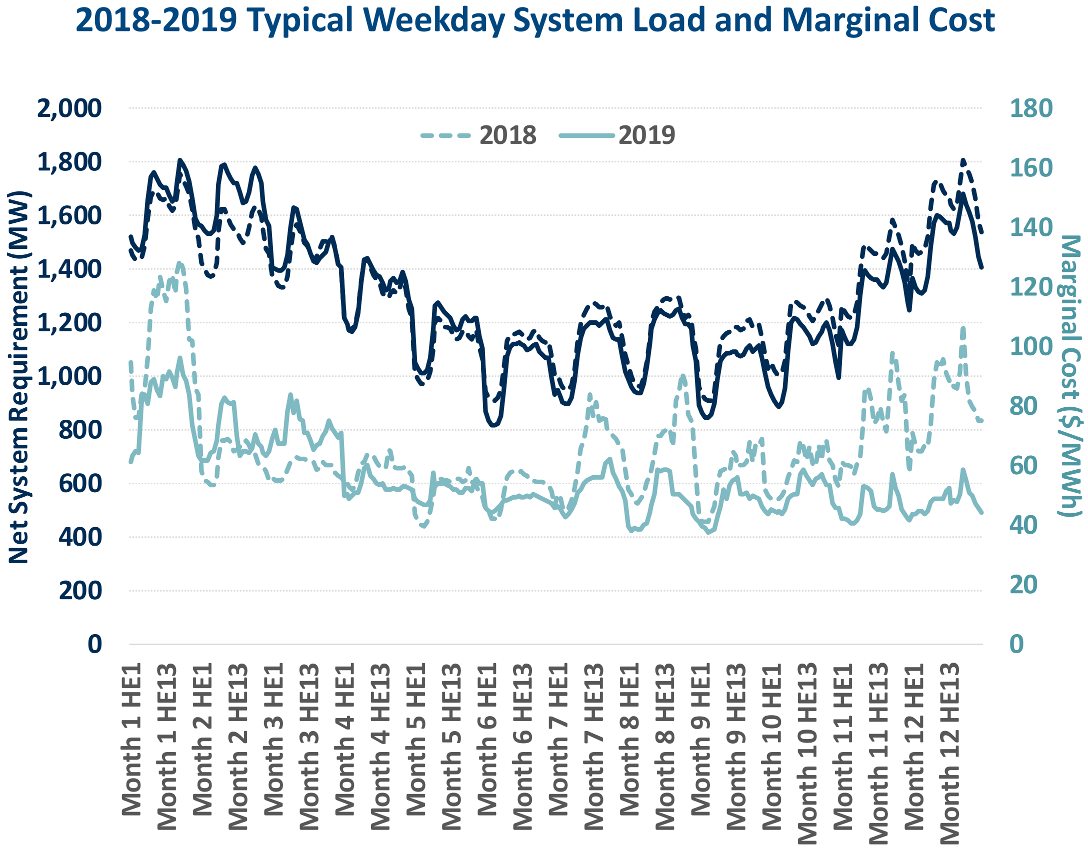
Cluster analysis attempts to determine the natural groupings (or clusters) of observations, such that observations in the same group are as similar to each other as possible

We used K-means cluster, one of the most commonly-used methods. It groups observations by minimizing Euclidean distances between them.

- The procedure begins with k initial group centers (**4 groups** in our case). Observations are assigned to the group with the closest center. The mean of the observations assigned to each of the groups is computed, and the process repeats, until a new iteration no longer re-assigns any observations to a new cluster.
- We conducted clustering analysis on hourly **net system requirement** and **marginal cost** from 2018 and 2019, at both monthly and daily levels, for both weekdays and all winter days

System marginal cost is more volatile compared to the system load

Nova Scotia Power's marginal cost follows the pattern of load in general, but is more volatile



Cluster Analysis Findings

While we carried out the clustering analysis at both monthly and daily levels, we found that:

- Daily level clustering is more suitable for system load analysis because it captures more variation
- Monthly level clustering is more appropriate for marginal cost analysis because daily data was highly volatile

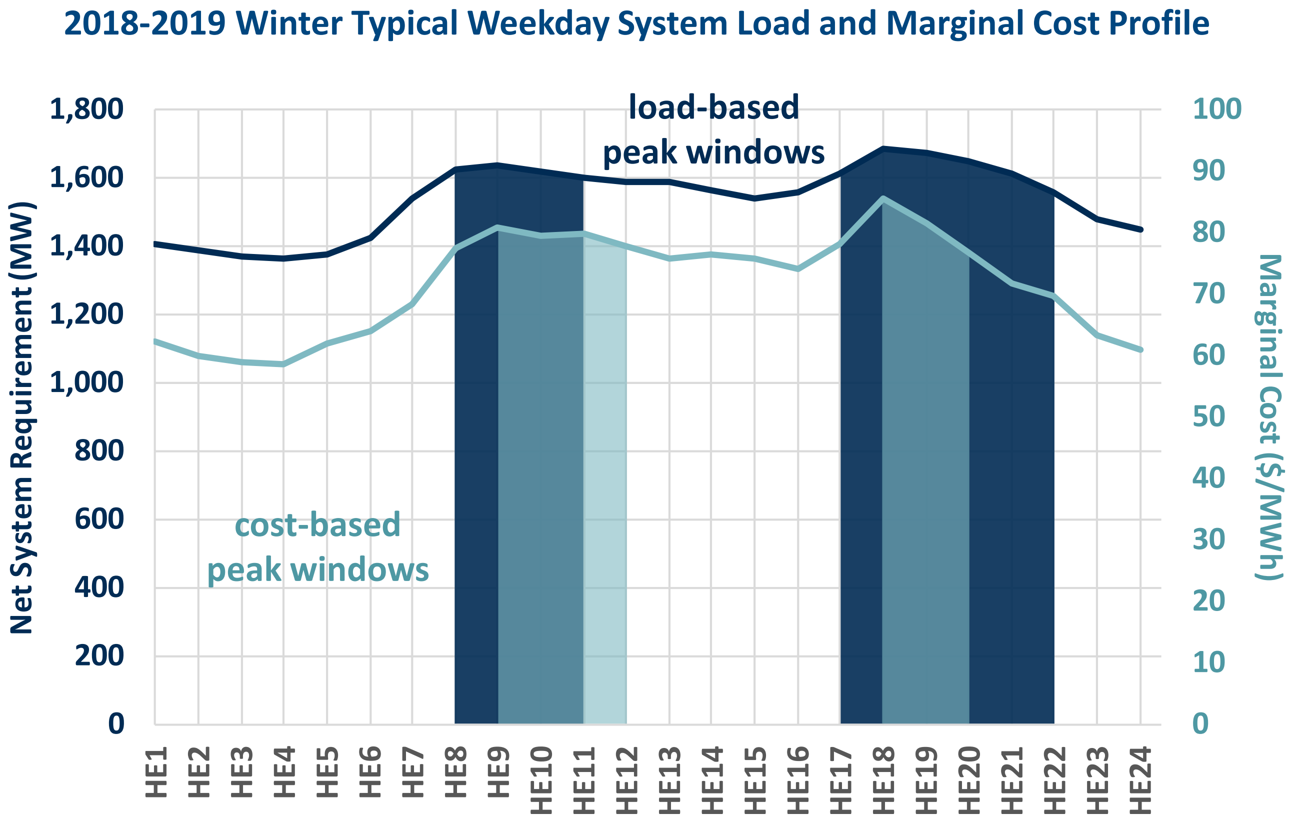
Our cluster analysis identified the following hours:

Peak Window Periods (Hour Ending)

	Weekdays only		
Season	Winter	Summer	Spring & Fall
Month	Jan, Feb, Nov, Dec	Jun, Jul, Aug, Sep	Mar, Apr, May, Oct
Load-based cluster			
Month-level	9, 18-20	12-18	8-10
Day-level	8-10, 17-21	13-19	8-12
Cost-based cluster			
Month-level	9-11, 18-19	12, 14, 17	7-10
Day-level	13-20	11-12	11, 15-20

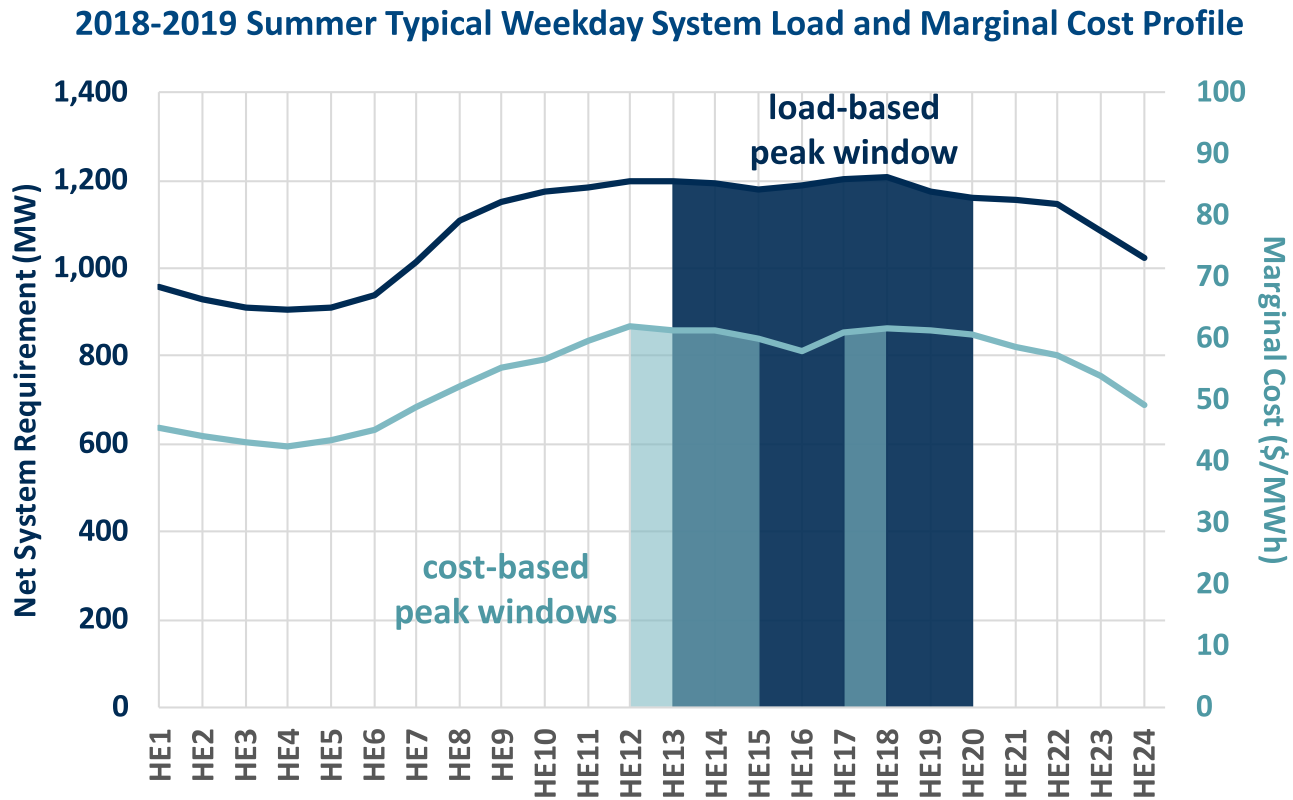
Proposed **Winter Peak Period** Definition

Based on our recommendation, NS Power designated HE8 – HE11 & HE17 – HE20 as the Winter peak window



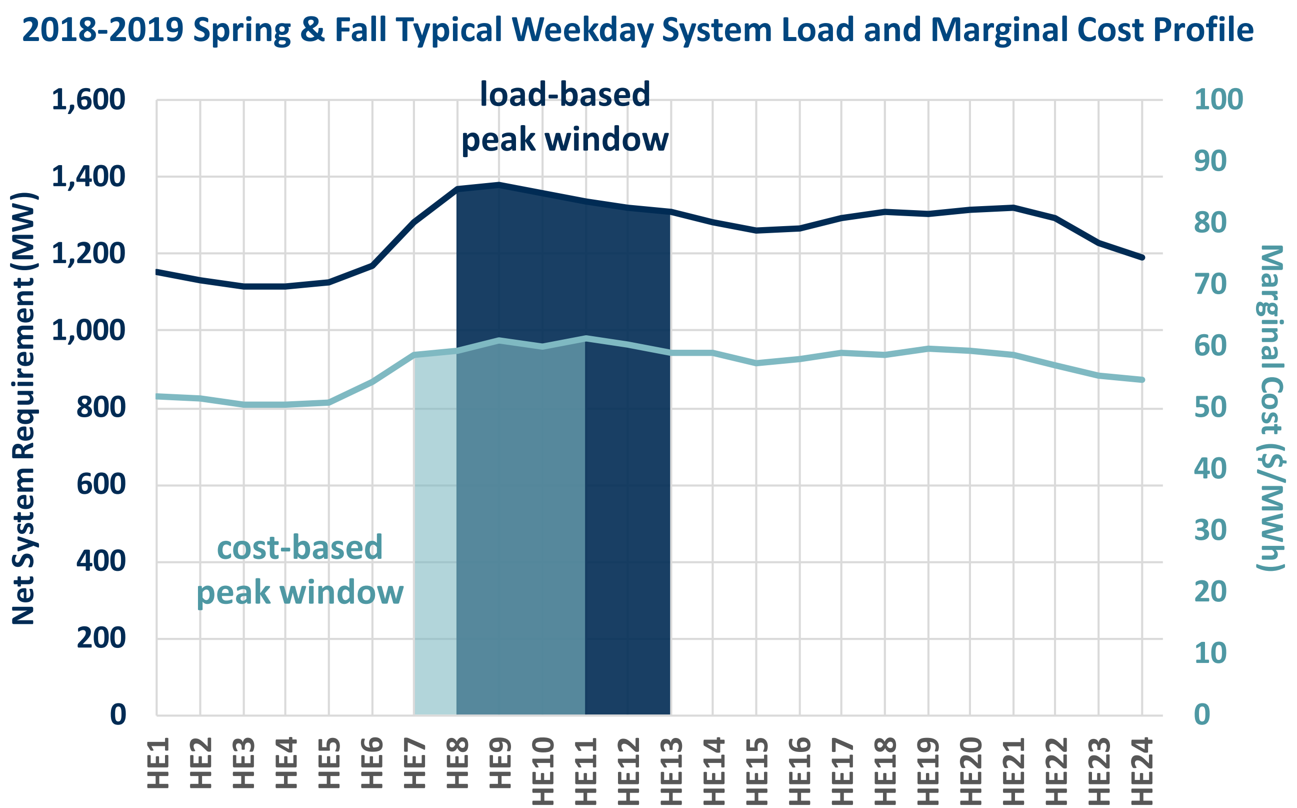
Proposed **Summer Peak Period** Definition

Based on our recommendation, NS Power designated HE13 – HE19 as the Summer peak window



Proposed **Spring & Fall Peak Period** Definition

Based on our recommendation, NS Power designated HE8 – HE12 as the Spring & Fall peak window



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Development of Time Varying Pricing Options

NS POWER TVP DESIGN APPROACH

PRESENTED TO

NS Power

PRESENTED BY

Ahmad Faruqui, Ph.D.
Sanem Sergici, Ph.D.

June 2020

THE Brattle GROUP

Scope of Analysis

This presentation summarizes the time varying rate design process followed by Nova Scotia Power Rates team

While NS Power designed the same set of TVPs for every rate class using similar structures, the rates summarized in this presentation are restricted to the Residential Non-ETS class to avoid repetition

- The Residential non-ETS class comprises 98% of the customers in the Residential class. The other 2%, Residential Electric Thermal Storage (ETS) customers, are on TOU rates

Rates for other classes will have similar structures, but different values for peak, off-peak and critical prices due to different allocated costs

Following this process, Nova Scotia Power designed a menu of TVP options

These time-varying rate options are described below alongside the standard offer rate (SOR)

	# TOU Seasons	CPP?	Winter Definition	Description
SOR	0	No	*n/a*	Constant flat volumetric charge in all hours of the year
CPP/SOR	0	Yes	*n/a*	Constant flat volumetric charge in all hours of the year, except for CPP hours
TOU #1	3	No	Nov – Feb	Peak and off-peak periods in each of the three seasons; Separate flat rates in Spring & Fall and Summer, with seasonal differentiation
TOU #2	3	No	Nov – Feb	Peak and off-peak periods in each of the three seasons; Single flat rate in Spring & Fall and Summer, with no seasonal differentiation
TOU #3A	1	No	Nov – Feb	Peak and off-peak periods in Winter only; Flat rate in Spring & Fall and Summer
TOU #3B	1	No	Nov – Mar	Peak and off-peak periods in Winter only; Flat rate in Spring & Fall and Summer
TOU #4A	1	No	Nov – Feb	Peak period in Winter only; Flat rate in all remaining hours, except for CPP hours
TOU/CPP #4A	1	Yes	Nov – Feb	Peak period in Winter only; Flat rate in all remaining hours, except for CPP hours
TOU #4B	1	No	Nov – Mar	Peak period in Winter only; Flat rate in all remaining hours
TOU/CPP #4B	1	Yes	Nov – Mar	Peak period in Winter only; Flat rate in all remaining hours, except for CPP hours

Nova Scotia Power's Rate Design Process
High Level Approach

NS Power Rates team applied the 2014 test year data from the 2013 GRA COSS, with the 2014 base cost of fuel (BCF) rate components replaced with the BCF from the 2020-2022 Rate Stability Plan (RSP)

Step 1: Identify overall structure of time varying rates guided by the cluster analysis done by Brattle

Step 2: Align peak to off-peak energy charge ratios under TOU Rates with the ratios of peak to off-peak marginal class costs in each season

Step 3: Develop TOU rates on the basis of revenue neutrality in cost recovery

Step 4: Develop CPP and TOU/CPP rates on the basis of revenue neutrality in cost recovery

Customer and demand charges were kept intact as approved for use in the 2013 GRA

Nova Scotia Power's Rate Design Process

Step 1: Identify overall structure of TVPs

- As marginal costs were similar for Spring/Fall versus Summer, NS Power determined the peak and off-peak energy charges for these two seasons jointly such that they were the same charges applied in both seasons, however, they would continue to apply during different time windows within each season **(Option #2 TOU)**
- Due to the fact that NS Power is a winter peaking utility with all of its investment in generation and transmission and most of its investment in distribution being driven by winter peaks, the Company considered four hybrid TOU/Flat rate options:
  - TOU differentiated winter season from November to February and flat rate during remaining months **(Option #3A TOU)**
  - TOU differentiated winter season from November to March and flat rate during remaining months **(Option #3B TOU)**
  - Peak TOU rate during winter season from November to February and the same energy rate during off-peak hours from November to February and all hours during the remaining months of the year **(Option #4A TOU)**
  - Peak TOU rate during winter season from November to March and the same energy rate during off-peak hours from November to March and all hours during the remaining months of the year **(Option #4B TOU)**

The Company tested the effect of inclusion of March in the winter period because there is a fair number of critical load and marginal cost events during this month with a potential to drive infrastructure investment going forward

Step 2: Align peak to off-peak energy charge ratios with seasonal marginal costs

- Hourly class load shapes from the 2014 test year have been aggregated by TVP periods as determined by the results of the Cluster Analysis (3 seasons with two time of day periods each)
- Calculated average system (at generator's gate) hourly marginal fuel cost (c/kWh) by TVP periods based on a three year period 2020 – 2022
- Calculated average hourly marginal fuel cost by TVP periods for each rate class (at the customer meter) by applying COSS-based line loss adjustment
- Determined demand-related costs from the 2014 COSS across seasonal peak periods for each rate class (at the customer meter) consistent with the distribution of each class average marginal fuel costs across seasonal peak periods
- Determined total average marginal cost in cents per kWh for each rate class by adding the average marginal fuel costs and demand-related unit costs by TVP periods

Step 3: Develop TOU rates on the basis of revenue neutrality in cost recovery

TOU Rates designed to match annual revenues under standard offer rate (SOR) energy charges (c/kWh) under an assumption that all customers are placed under the TOU rates and none of them change their hourly usage pattern in response to TVP pricing signals

Following process was used for determination of TOU energy rates:

1. Determined unbalanced class revenues by multiplying the time varying average marginal costs (c/kWh) of each class by kWh class usage in corresponding TVP periods for each class and add them up to other revenue components: customer charge revenue or demand charge revenue
2. Scaled the time varying average marginal costs (c/kWh) of each class across the board to match the annual revenues from the 2014 Test year with the BCF rate components from the 2020 – 2022 RSP
   - initially conducted rate analysis for each of the 3 years under the RSP but eventually shifted its focus to year 2022 only
3. Determined the non-FAM component of the c/kWh charge by subtracting the base cost of fuel (BCF) component under the SOR from the scaled energy charges above

Nova Scotia Power's Rate Design Process

Step 4: Develop CPP and TOU/CPP rates on the basis of revenue neutrality in cost recovery

TOU/CPP Rates designed to match annual revenues under standard offer rate (SOR) energy charges (c/kWh) under an assumption that all customers are placed under the TOU/CPP rates and none of them change their hourly usage pattern in response to TVP pricing signals

Following process was used for determination of CPP or TOU/CPP rates:

1. Determined unbalanced class revenues by setting CPP energy charge (c/kWh) at a level which would recover each class demand-related costs during the critical peak period of 100 hours and add the associated CPP revenue to other revenue components: energy charges under standard offer (CPP option) or under TOU design (Combined CPP/TOU option), and customer charge or demand charge as applicable
2. If CPP used in conjunction with SOR; scaled the non-FAM component of the energy charges under the SOR across-the-board to match annual revenues from those from the 2014 Test year with the BCF rate components from the 2020 – 2022 RSP
3. If CPP used in conjunction with TOU rates followed this two-step conditional process:
    - scaled down the fixed cost component of the off-peak charges to match annual revenues with those of the 2014 Test year with the BCF rate components from the 2020 – 2022 RSP
    - If scaling down the off-peak fixed component down to zero still left surplus revenue, scaled the fixed cost component of the peak energy charge to balance

Other Considerations in the Rate Design Process

- **Test gradual reduction in the number of pricing periods as justified by:**
  - small cost differential among benchmark TVP periods established in Cluster Analysis
  - retainment of essential usage drivers behind cost causation on NS Power's system (winter peaking utility)
  - selection of the most effective TVP options in terms of their system peak reduction potential and ease of implementation (i.e., chose to target broad customer groups and end uses such as residential space heating instead of market niches such EVs or agricultural irrigation)

- **Test various TVP ratios informed by:**
  - Effect of varying peak to off-peak ratios and CPP levels; as justified by various cost standards and external industry metrics; on system load reduction, customer bills and customer service uptake
  - Effect of different cost based standards: marginal fuel costs, marginal fuel costs combined with marginal generation capacity costs, marginal fuel costs combined with embedded demand-related costs from COSS

Standard Offer Rate

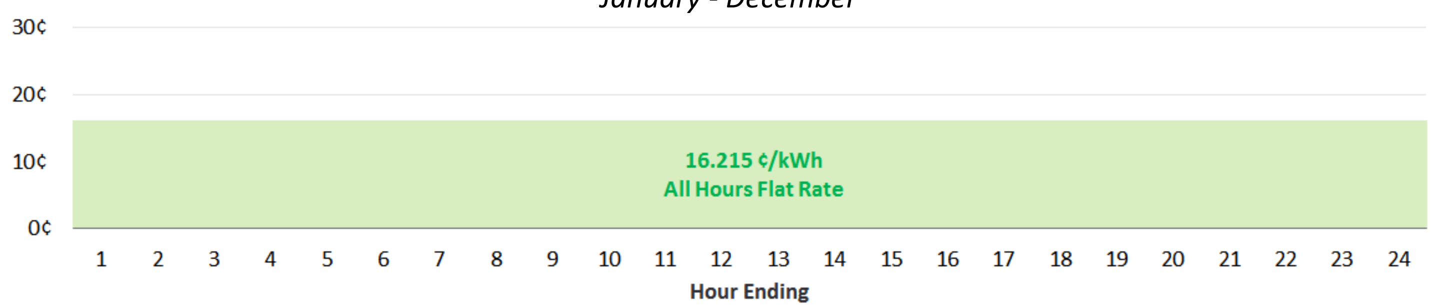
The following slides illustrate the rate structure of several proposed time varying pricing (TVP) tariffs for NS Power in 2022

- These rates contrast with the current Standard Offer Rate (shown below), which is characterized by a flat volumetric energy charge in all hours
- All tariffs also include a fixed charge of $10.83/month, which is not reflected in the illustrations
- These illustrations assume that the peak period consists of hours ending 8-11 AM and 5-8 PM in winter, 8 AM-noon in spring & fall, and 1-7 PM in summer

Standard Offer Rate (SOR)

Year-Round

January - December



Proposed Rate Designs
Overview of Residential Rates

The table below details the specific rate levels under each proposed TVP for the Residential Non-ETS class

- For TOU #3B, TOU #4B, and TOU/CPP #4B, **Winter** corresponds to November- March, **Spring & Fall** to April, May and October, and **Summer** to June – September
- For all other rates, **Winter** corresponds to November- February, **Spring & Fall** to March - May and October, and **Summer** to June – September

	Customer ($/month)	On-Peak Rate (c/kWh)			Flat or Off-Peak Rate (c/kWh)			CPP Rate (c/kWh)
		Winter	Spring & Fall	Summer	Winter	Spring & Fall	Summer	
SOR	*$10.83*				*16.215*	*16.215*	*16.215*	
CPP/SOR	$10.83				11.682	11.682	11.682	231.271
TOU #1	$10.83	46.928	28.894	29.524	11.712	8.403	7.915	
TOU #2	$10.83	46.951	29.350	29.350	11.717	8.169	8.169	
TOU #3A	$10.83	62.629			12.052	8.539	8.539	
TOU #3B	$10.83	52.245			11.799	8.088	8.088	
TOU #4A	$10.83	64.131			9.676	9.676	9.676	
TOU/CPP #4A	$10.83	50.673			6.933	6.933	6.933	231.271
TOU #4B	$10.83	53.822			9.610	9.610	9.610	
TOU/CPP #4B	$10.83	41.220			6.933	6.933	6.933	231.271

Notes: The other rate options excluded from this presentation consist of TOU/CPP variations of the #1 TOU, #2 TOU, and #3 TOU rate options.

Proposed Rate Designs

All-in Peak to Off-Peak (P/OP) Ratios

Customers respond by shifting their usage from higher priced hours to lower priced hours. Thus, the ratio of peak-to-off-peak (P/OP) prices is an important metric to gauge the expected load impact

- Based on the empirical evidence from the previous pilots, P/OP ratio would ideally be greater than 2 to incentivize some amount of load shifting
- If the ratio is greater (>=4), this will create a meaningful opportunity for customers to change their consumption patterns and achieve bill savings under new TVRs
- Nova Scotia Power TVRs have P/OP ratios greater than 3.0, largely achieved by assigning the recovery of capacity costs during the peak hours

	Peak/Off-Peak Ratio			
	Winter	Spring & Fall	Summer	CPP
SOR/CPP				17.7
TOU #1	3.7	3.1	3.3	
TOU #2	3.7	3.2	3.2	
TOU #3A	4.7			
TOU #3B	4.0			
TOU #4A	5.9			
TOU/CPP #4A	6.2			27.7
TOU #4B	5.0			
TOU/CPP #4B	5.1			27.7

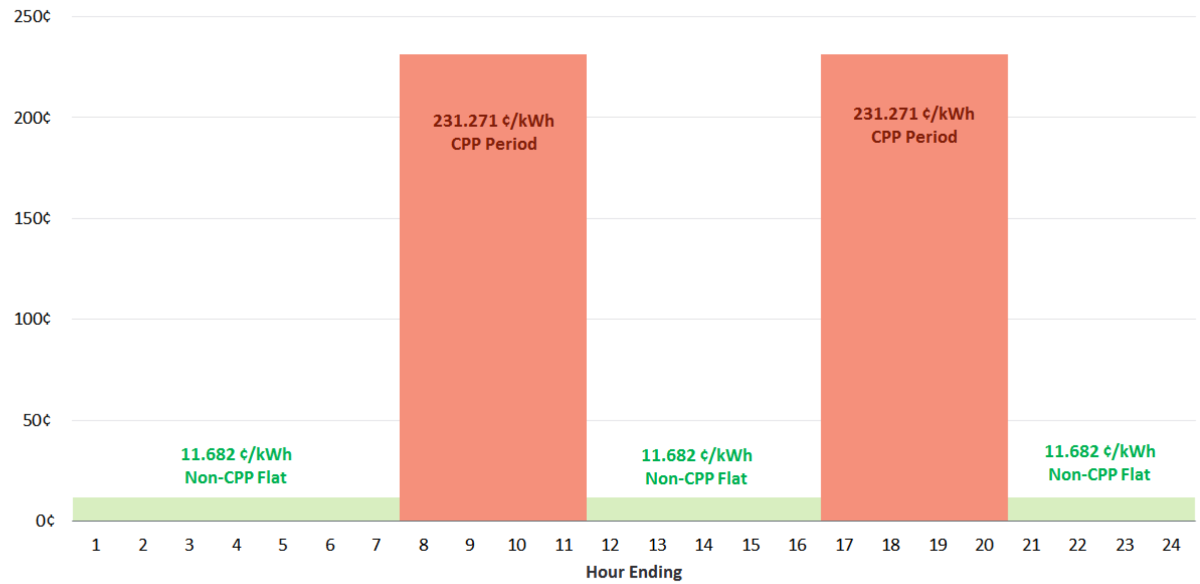
Notes: Ratios shown are **all-in ratios** computed as (On-Peak c/kWh energy rate + Levelized Fixed Charge) / (Flat or Off-Peak c/kWh energy rate + Levelized Fixed Charge) in the same period.

Proposed Rate Designs
CPP/SOR

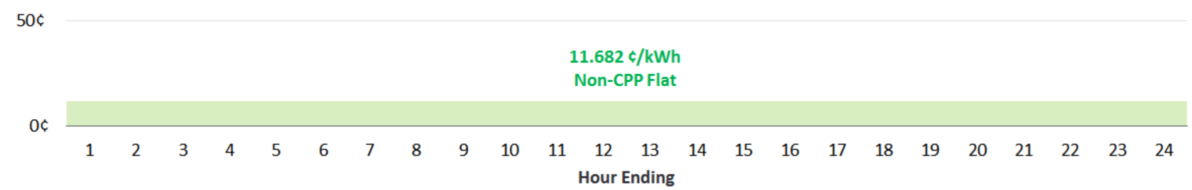
Characterized by:

- A critical peak pricing (CPP) rate in the highest load hours of the year (assumed to occur in winter)
- A flat rate in all non-CPP hours that is approximately 5 cents lower than under the SOR
- No seasonal differentiation

CPP Event Day (assumed in winter peak)



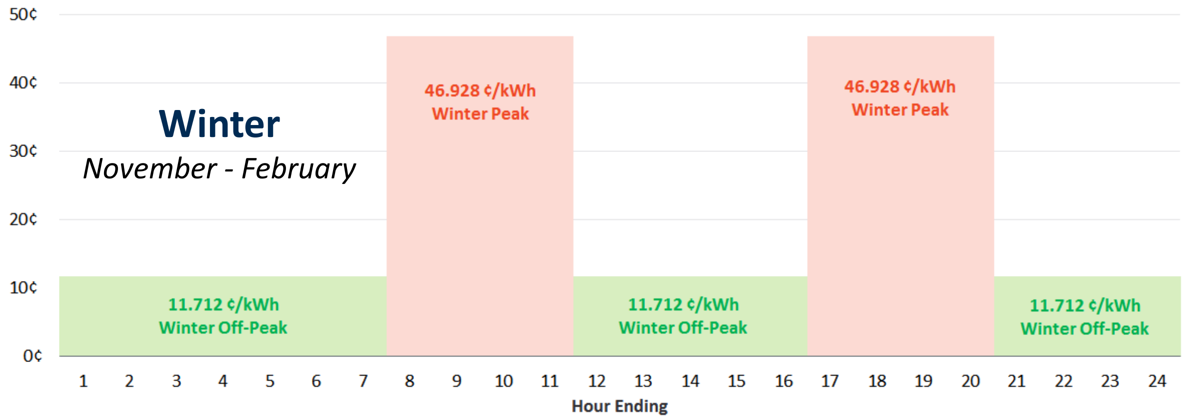
Non-CPP Event Day

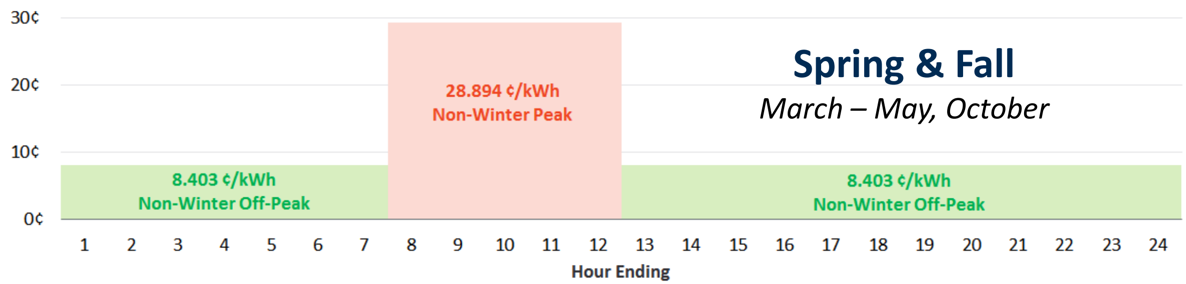


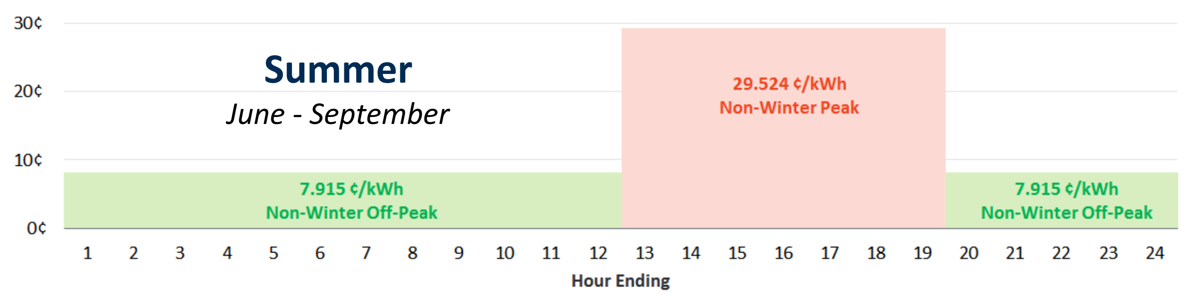
Proposed Rate Designs
TOU #1

Characterized by:

- Peak and off-peak periods in each of the three seasons
- Seasonal differentiation between Spring & Fall vs. Summer rates
- A winter off-peak rate nearly equal to the flat rate under SOR/CPP
- No CPP period



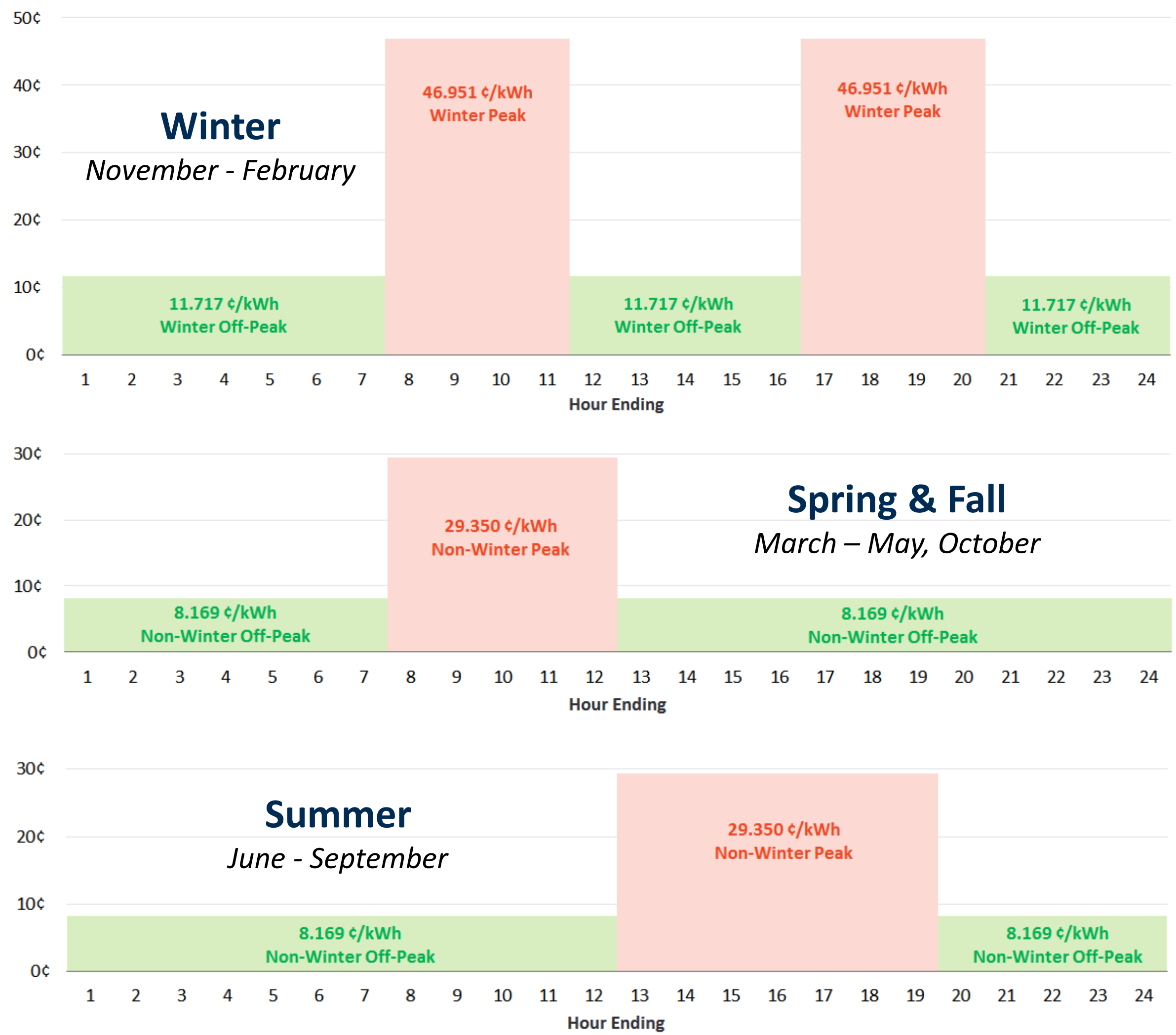




Proposed Rate Designs
TOU #2

Characterized by:

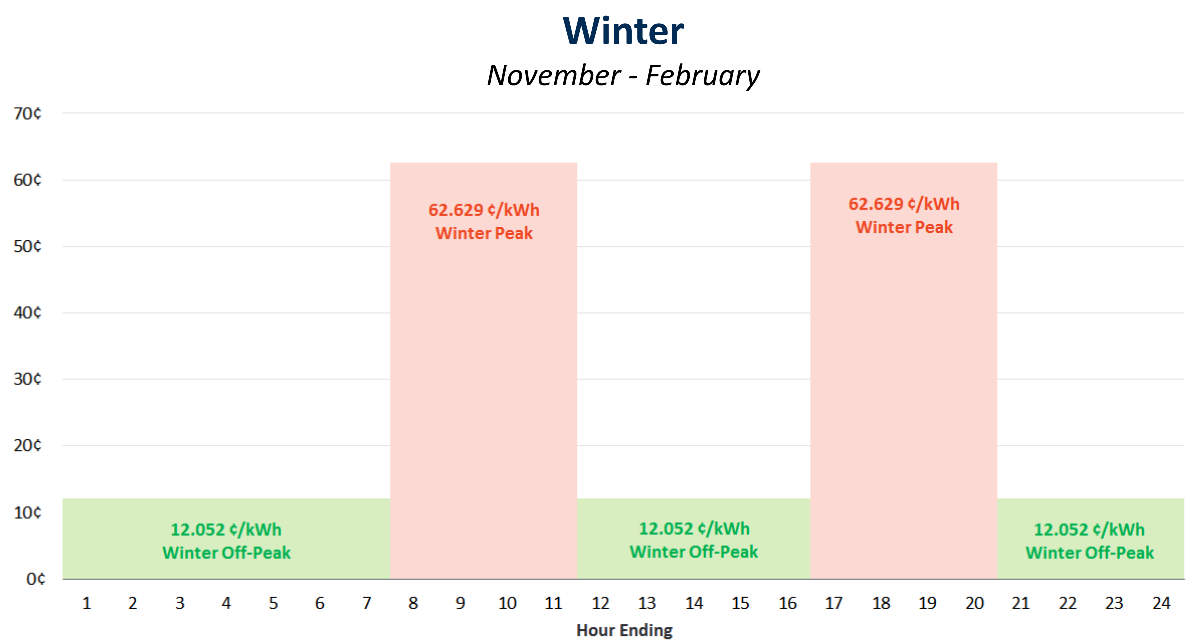
- Peak and off-peak periods in each of the three seasons
- Similar rate levels to TOU #1, but no seasonal differentiation between Spring & Fall vs. Summer rates
- No CPP period

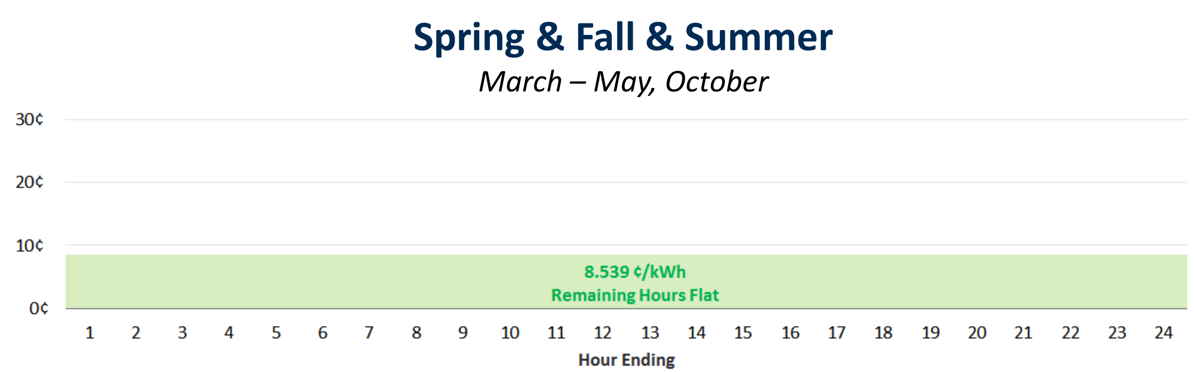


Proposed Rate Designs
TOU #3A

Characterized by:

- Peak and off-peak periods in Winter only, compared to flat rate in Spring & Fall and Summer
- Differentiation between the winter off-peak and non-winter flat rate, but no seasonal differentiation between spring, fall, and summer flat rates
- A winter peak rate nearly 35% higher than under rates TOU #1 and TOU #2
- No CPP period



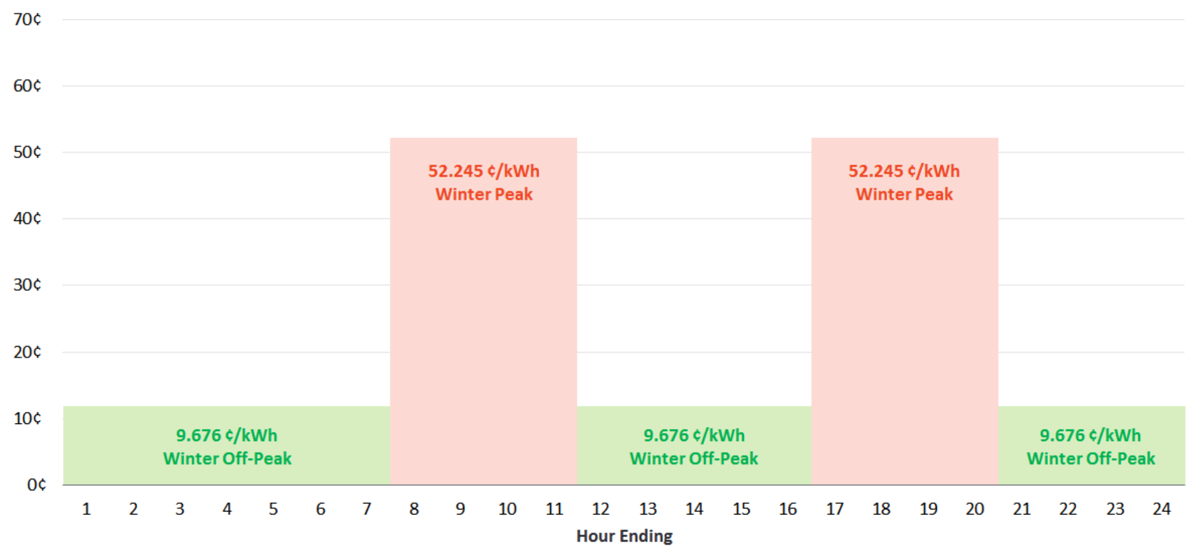


Proposed Rate Designs
TOU #3B

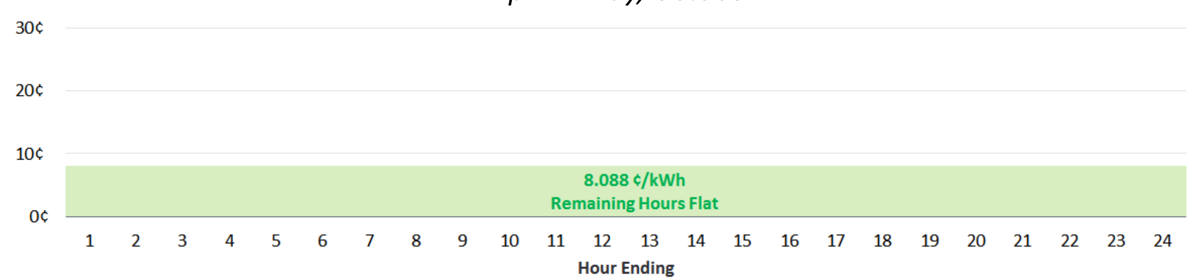
Characterized by:

- The same rate structure as TOU #3A, but with a longer Winter period that includes March
- Consistently lower rate levels than under TOU #3A, most notably with a winter peak rate nearly ten cents lower

Winter
November - March



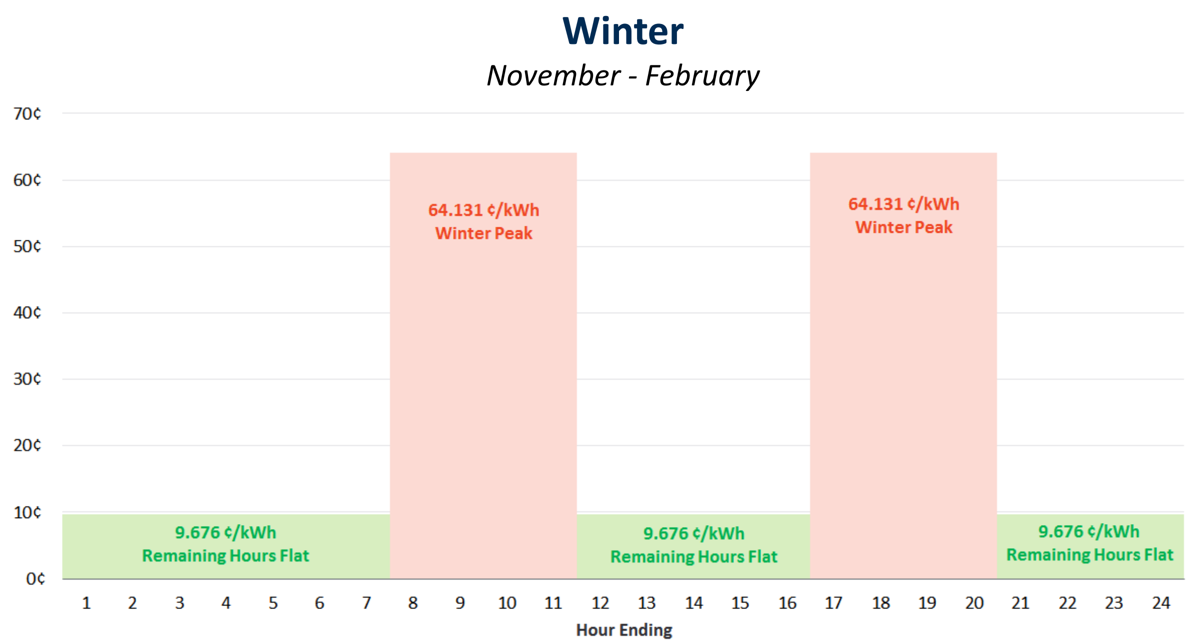
Spring & Fall & Summer
April – May, October

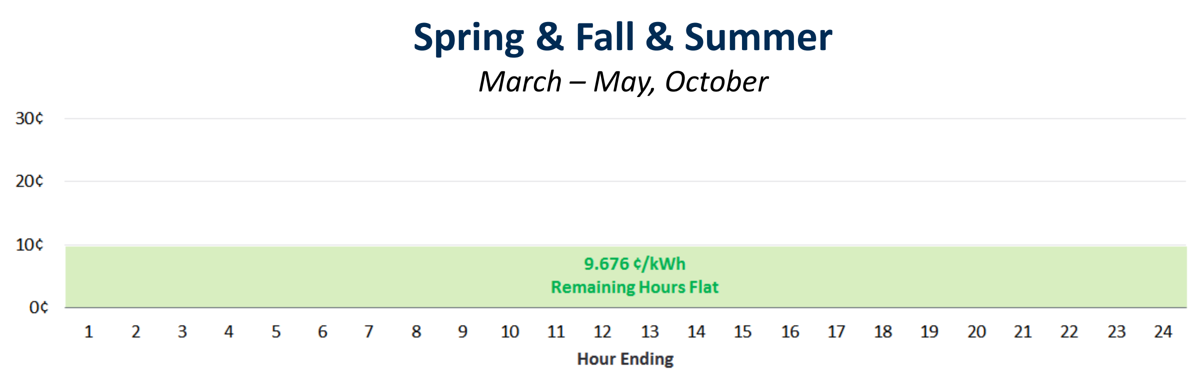


Proposed Rate Designs
TOU #4A

Characterized by:

- A peak period in winter only, and a constant flat rate in all remaining hours
- Unlike TOU #3A/#3B, no seasonal differentiation between the winter off-peak rate and the flat rate in spring, summer, and fall
- The highest winter peak rate among all proposed TOU offerings
- No CPP period





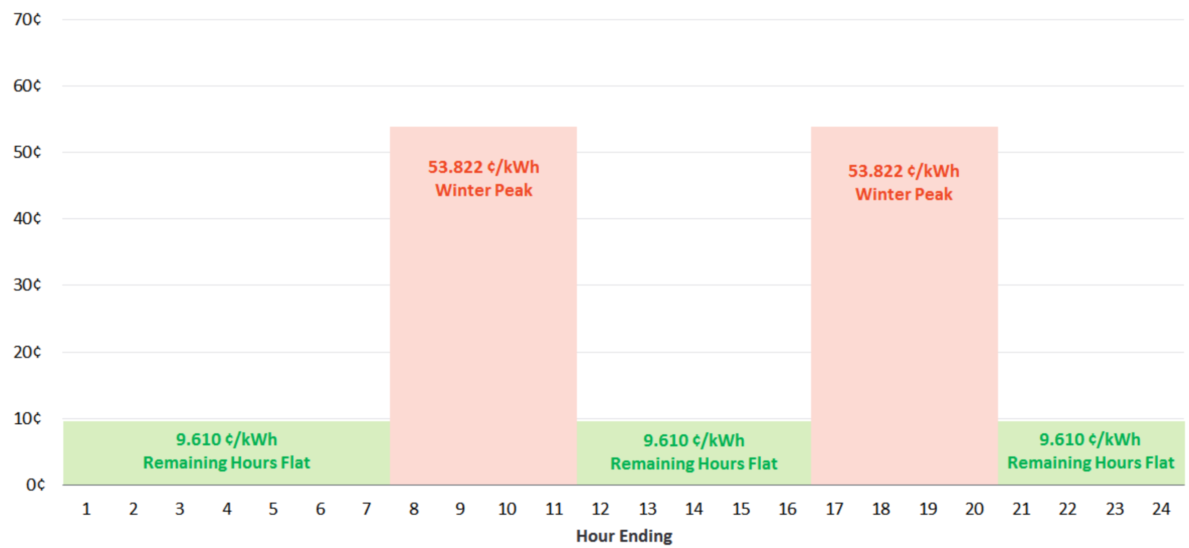
Proposed Rate Designs
TOU #4B

Characterized by:

- The same rate structure as TOU #3A, but with a longer Winter period that includes March
- A winter peak rate roughly ten cents lower than under TOU #3A, with a similar flat rate in all remaining hours

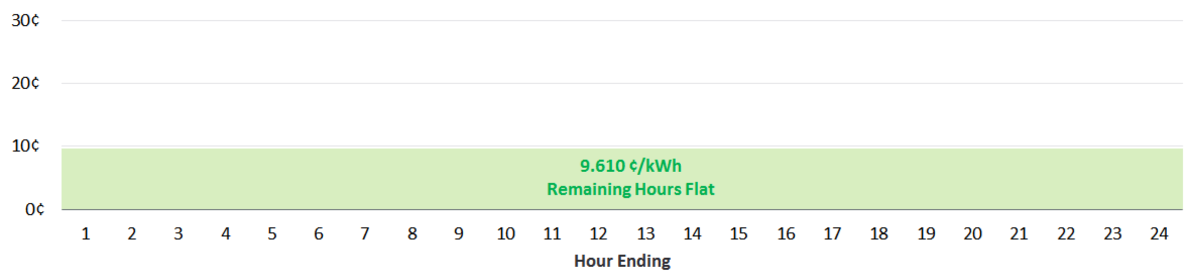
Winter

November - March



Spring & Fall & Summer

April – May, October



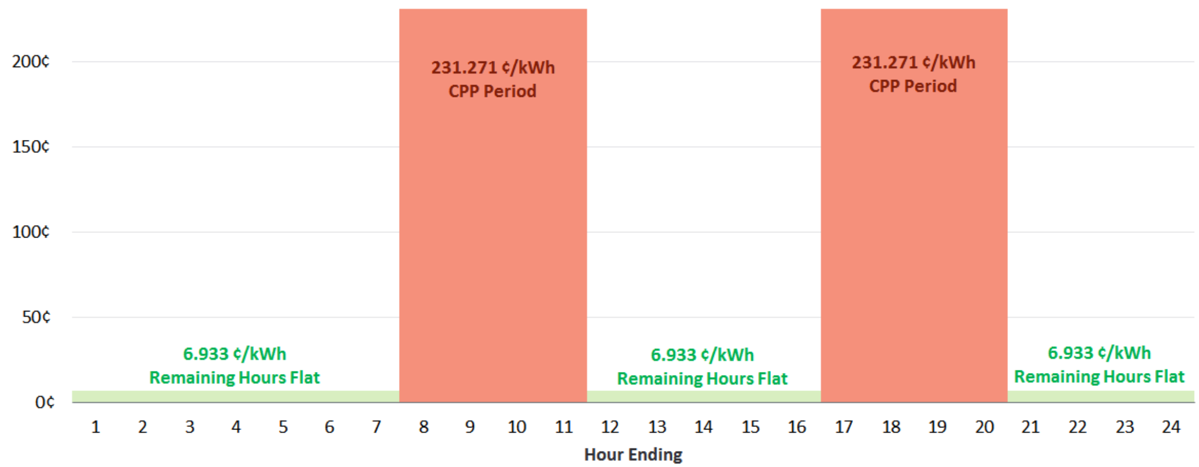
Proposed Rate Designs
TOU/CPP #4A

Characterized by:

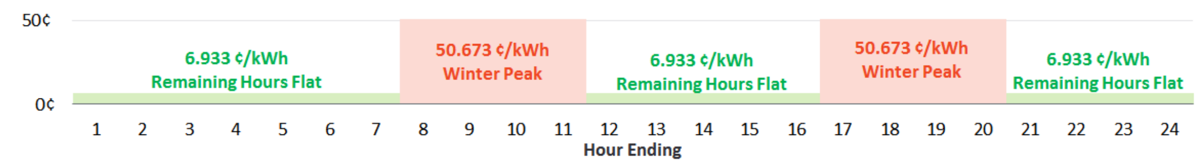
- A peak rate in winter only coupled with a CPP rate in the highest load hours of the year, the latter being equal to the CPP rate under the SOR/CPP offering
- Consistently lower rates than under TOU #4A in all non-CPP hours. This flat rate is the lowest across all offerings

Winter
November - February

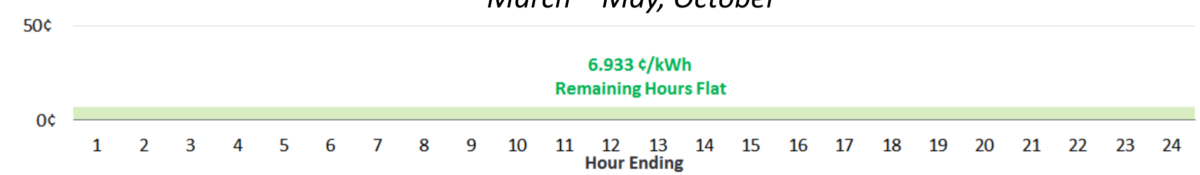
CPP Event Day (assumed in winter peak)



Non-CPP Event Day



Spring & Fall & Summer
March – May, October



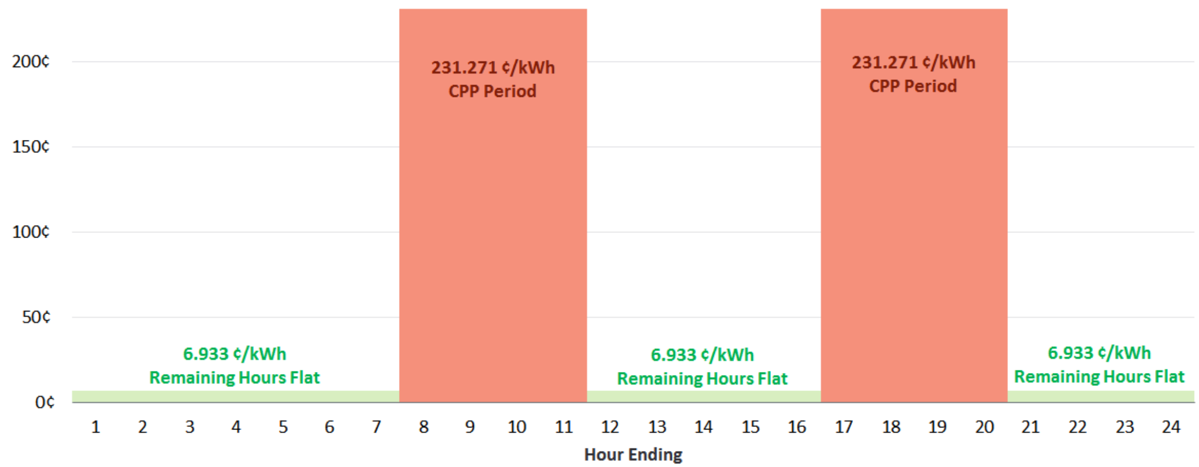
Proposed Rate Designs
TOU/CPP #4B

Characterized by:

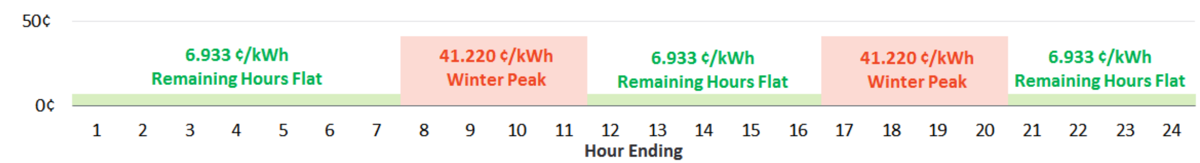
- The same rate structure as TOU/CPP #4A, but with a longer Winter period that includes March
- A winter peak rate nearly ten cents lower than under TOU/CPP #4A, but the same CPP rate and the same flat rate in all remaining hours

Winter
November - March

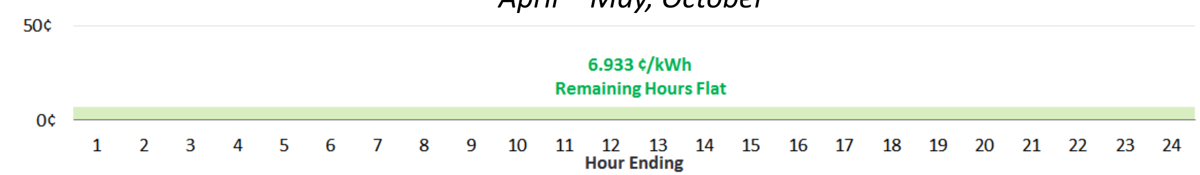
CPP Event Day (assumed in winter peak)



Non-CPP Event Day



Spring & Fall & Summer
April – May, October



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Customer and System Load Impacts of Proposed TVPs

ANALYSIS OF RESIDENTIAL (NON-ETS), SMALL GS, AND GS CLASSES

PRESENTED TO
NS Power

PRESENTED BY
Ahmad Faruqui
Sanem Sergici

June 2020

THE Brattle GROUP

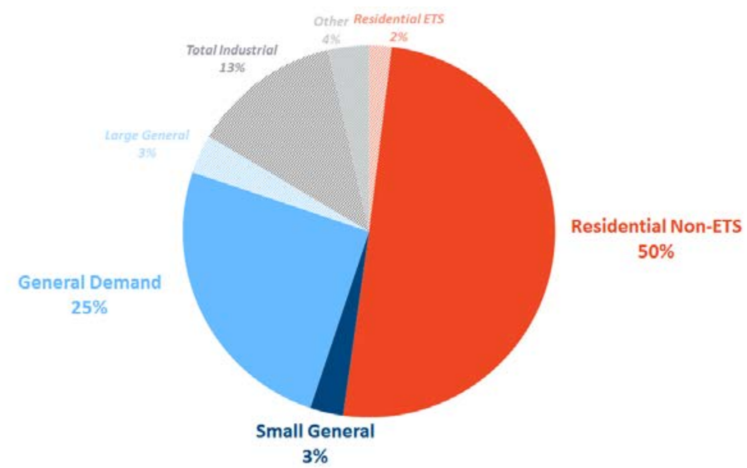
Scope of Analysis

This presentation summarizes the analysis we have carried out to assess the average customer and system load impacts of Nova Scotia Power's proposed TVPs

While NS Power designed the same set of TVPs for every rate class, the initial analysis summarized in this presentation is restricted to the Residential Non-ETS, Small General, and General Demand classes

- As show, these three classes together account for approximately 78% of NS Power's annual revenues
- The Residential non-ETS class comprises 98% of the customers in the Residential class. The other 2%, Residential Electric Thermal Storage (ETS) customers, are on TOU rates

Total Revenue Breakdown by Rate Class



Source: NS Power revenue data

Nova Scotia Power designed a rich menu of TVP options

NS Power has subsequently narrowed down the considered TVR options to the CPP/SOR and TOU #3B rates

– The following slides refer to these selected rates as “CPP” and “TOU” respectively

	# TOU Seasons	CPP?	Winter Definition	Description
SOR	0	No	*n/a*	Constant flat volumetric charge in all hours of the year
CPP/SOR	0	Yes	*n/a*	Constant flat volumetric charge in all hours of the year, except for CPP hours
TOU #1	3	No	Nov – Feb	Peak and off-peak periods in each of the three seasons; Separate flat rates in Spring & Fall and Summer, with seasonal differentiation
TOU #2	3	No	Nov – Feb	Peak and off-peak periods in each of the three seasons; Single flat rate in Spring & Fall and Summer, with no seasonal differentiation
TOU #3A	1	No	Nov – Feb	Peak and off-peak periods in Winter only; Flat rate in Spring & Fall and Summer
TOU #3B	1	No	Nov – Mar	Peak and off-peak periods in Winter only; Flat rate in Spring & Fall and Summer
TOU #4A	1	No	Nov – Feb	Peak period in Winter only; Flat rate in all remaining hours, except for CPP hours
TOU/CPP #4A	1	Yes	Nov – Feb	Peak period in Winter only; Flat rate in all remaining hours, except for CPP hours
TOU #4B	1	No	Nov – Mar	Peak period in Winter only; Flat rate in all remaining hours
TOU/CPP #4B	1	Yes	Nov – Mar	Peak period in Winter only; Flat rate in all remaining hours, except for CPP hours

Rate Design Sensitivities
TOU Rate

The TOU rate (TOU #3B) involves peak and off-peak rates in Winter only and flat rates in non-winter months

In order to inform peak/off-peak load impact tradeoff, NS Power team designed this TOU rate with various ratios as shown below

(c/kWh)	On-Peak Rate	Flat or Off-Peak Rate	
	Winter Peak	*Winter Off-Peak*	*Non-Winter*
Residential Non-ETS			
Ratio = 4.4 (Base Option)	52.245	11.799	8.088
Ratio = 2	32.957	16.478	10.260
Ratio = 3	42.919	14.306	8.908
Ratio = 4	50.561	12.640	7.870
Small General Service			
Ratio = 4.5 (Base Option)	54.295	12.086	8.113
Ratio = 2	32.747	16.373	10.291
Ratio = 3	43.395	14.465	9.092
Ratio = 4	51.820	12.955	8.143
General Service			
Ratio = 4.1 (Base Option)	37.975	9.334	6.589
Ratio = 2	24.645	12.323	7.805
Ratio = 3	32.614	10.871	6.886
Ratio = 4	37.723	9.431	6.589

Notes: All rate options include a month fixed charge of $10.83 for Residential customers and $12.65 for Small GS customers. For GS, all rate options include a $10.50/kW demand charge.

- Note that while the TOU options are labeled according to the simple ratio of their peak to off-peak energy charges (*e.g.,* under TOU rate “Ratio = 2”, the on-peak rate in winter is twice the winter off-peak rate), we compute separate, **all-in peak ratios** inclusive of levelized fixed and demand charges to estimate load impacts

Rate Design Sensitivities

CPP Rate

The CPP rate charges a high, critical peak price in a limited set of hours whenever a CPP event is called, but it follows the same rate structure (at a lower price level) as the Standard Offer Rate in all remaining hours

In order to inform peak/off-peak load impact tradeoff, NS Power team designed this TOU rate with various ratios as shown below

(c/kWh)	On-Peak Rate	Flat Non-CPP Rate	
	CPP Event	*First Block*	*Second Block*
Residential Non-ETS			
231 c/kWh (Base Option)	231.271	11.682	
50 c/kWh	50.000	15.503	
100 c/kWh	100.000	14.449	
150 c/kWh	150.000	13.395	
200 c/kWh	200.000	12.341	
Small General Service			
268 c/kWh (Base Option)	267.620	12.393	11.328
50 c/kWh	50.000	15.911	14.202
100 c/kWh	100.000	15.103	13.542
150 c/kWh	150.000	14.295	12.882
200 c/kWh	200.000	13.486	12.221
General Service			
231 c/kWh (Base Option)	231.462	8.470	7.480
50 c/kWh	50.000	12.027	9.166
100 c/kWh	100.000	11.047	8.701
150 c/kWh	150.000	10.067	8.237
200 c/kWh	200.000	9.087	7.773

Notes: All rate options include a month fixed charge of $10.83 for Residential customers and $12.65 for Small GS customers. For GS, all rate options include a $10.50/kW demand charge. First block usage is defined as the first 200 kWh for Small GS customers, and the first 200 kWh per kW of maximum demand for GS customers. All additional kWh fall into the second block.

- We assume that critical pricing hours will be limited to the winter peak period, defined as hours ending **8-11 AM** and **5-8 PM** of **November through March**

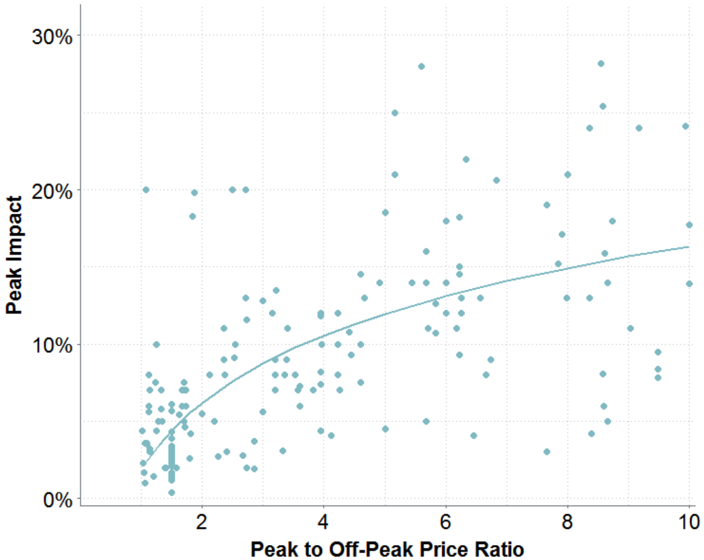
Estimating Load Impacts
Methodology

Using proposed 2022 rates as reference and usage data provided by NS Power, we estimated average customer response to the new rates according to the all-in peak/off-peak ratio of each rate

- Estimated peak impacts are based on regression analysis of 51 time-varying residential pilots with 228 price only (*i.e.,* without enabling technology) treatments in the Arcturus database (shown to the right)
- We assume **constant usage within each season** (*e.g.,* in response to a winter TOU rate, load is fully shifted from the winter peak to winter off-peak period)
- We used separate coefficients to estimate the impact for CPP and TOU rates, as the data implies higher responsiveness to the CPP rates compared to TOU

As described in the following slides, we then make adjustments to account for differences among rate classes and winter-peaking utilities, as well as assumed enrollment to compute aggregate impact

Estimated Impacts by P/OP Ratio for an Average Participant



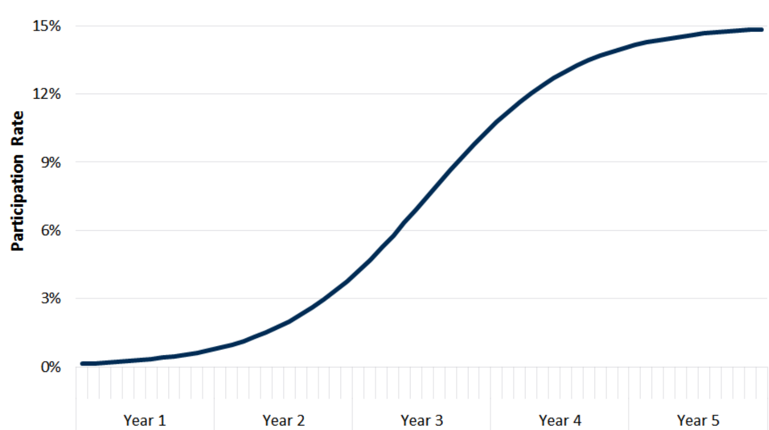
Notes: See Ahmad Faruqui , Sanem Sergici, and Cody Warner, "Arcturus 2.0: International Evidence on Time-Varying Rates," The Electricity Journal, 2017.

Estimating Load Impacts
Participation Assumptions

In estimating impacts, we assume that NS Power will offer opt-in TVP rates and it will reach 15% participation rate

- Results presented in this deck reflect the estimated impacts only once this enrollment level has been reached
  - Take-up generally follows an S-shaped rather than linear growth pattern (see the chart below for an hypothetical example). However, depending on the effectiveness of marketing, this enrollment level can be reached faster or slowed
- Utilities may alternatively deploy new rates on a mandatory (*i.e.,* full adoption) or opt-out basis. Typically, opt-out rates will have a higher adoption rate (closer to 75%), but customers will be less likely to respond to price signals than if they had actively selected their tariff
- New rates can be offered on an opt-in basis first to avoid any customer confusion and rate shocks, and later transitioned to a default mandatory basis

Illustrative Deployment Rate of New Opt-in TVP Option



Estimating Load Impacts
% Peak Reduction Assumptions

Using Brattle's Arcturus database, we have estimated average peak impacts for a customer enrolled in each TOU and CPP option presented earlier

- Given that the Arcturus database predominantly consists of residential summer-peaking utility pilots, we apply a **50% derating factor** to adjust for lower customer response under a **winter-peaking utility** like NS Power
- For the **Small General Service class**, we also applied an **additional 50% derating factor** to adjust for lower customer response from Small General Service customers, whose demand is **generally less elastic** than that of residential customers

By applying the assumed 15% participation rate to the adjusted per customer estimates, we then calculate the % change in the peak period usage for each customer class

For each customer class, the following slides summarize the estimated average peak impacts per participant as well as the resulting peak demand reductions for the system

Residential TVP Designs
Peak to Off-Peak (P/OP) Ratios

Customers respond by shifting their usage from higher priced hours to lower priced hours. Thus, the ratio of peak-to-off-peak (P/OP) prices is an important metric to gauge the expected load impact

- Based on the empirical evidence from the previous pilots, P/OP ratio would ideally be greater than 2 to incentivize some amount of load shifting
- If the ratio is greater (>=4), this will create a meaningful opportunity for customers to change their consumption patterns and achieve bill savings under new TVRs
- Nova Scotia Power TVRs have P/OP ratios greater than 3.0, largely achieved by assigning the recovery of capacity costs during the peak hours

	Peak/Off-Peak Ratio			
	Winter	Spring & Fall	Summer	CPP
SOR/CPP				17.7
TOU #1	3.7	3.1	3.3	
TOU #2	3.7	3.2	3.2	
TOU #3A	4.7			
TOU #3B	4.0			
TOU #4A	5.9			
TOU/CPP #4A	6.2			27.7
TOU #4B	5.0			
TOU/CPP #4B	5.1			27.7

Notes: Ratios shown are **all-in ratios** computed as (On-Peak c/kWh energy rate + Levelized Fixed Charge) / (Flat or Off-Peak c/kWh energy rate + Levelized Fixed Charge) in the same period.

Residential Load Impacts
% Peak Reduction (for an avg. residential participant)

Using a regression fit to the Arcturus database, with binary variables for CPP vs. TOU rates, we estimated average peak impacts for a customer enrolled in each TVP rate proposed by Nova Scotia Power

- Given that the Arcturus database predominantly consists of summer-peaking utility pilots, we then apply a **50% derating factor** to adjust for lower customer response for a **winter-peaking utility** like NS Power

	Implied Arc Impact		Impact After 50% Derate	
	TOU	CPP	TOU	CPP
SOR/CPP		-23.8%		-11.9%
TOU #1	-8.8%		-4.4%	
TOU #2	-8.8%		-4.4%	
TOU #3A	-10.2%		-5.1%	
TOU #3B	-9.4%		-4.7%	
TOU #4A	-11.4%		-5.7%	
TOU/CPP #4A	-11.8%	-27.2%	-5.9%	-13.6%
TOU #4B	-10.6%		-5.3%	
TOU/CPP #4B	-10.6%	-27.2%	-5.3%	-13.6%

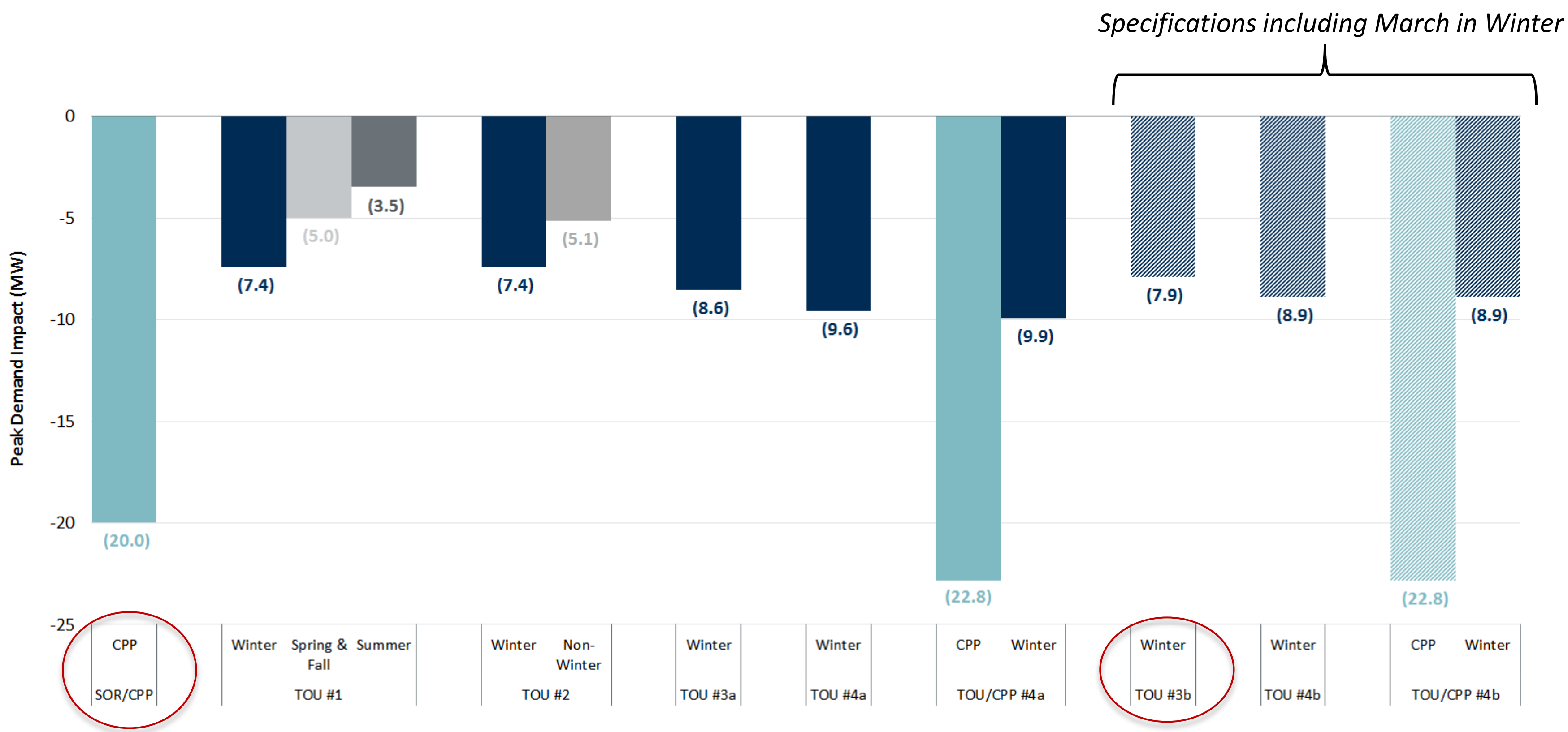
Notes: For TOU rates #1 and #2, TOU impacts shown represent winter impacts. Implied Arc Impacts are computed using all-in ratios, which consider a levelized fixed charge in both the on-peak and off-peak price.

By applying an assumed 15% participation rate to the adjusted per customer estimates, we then calculate the % change in the peak period usage for the entire Residential non-ETS class (shown in the following slide)

Residential Load Impacts

Peak Demand Reduction (MW)

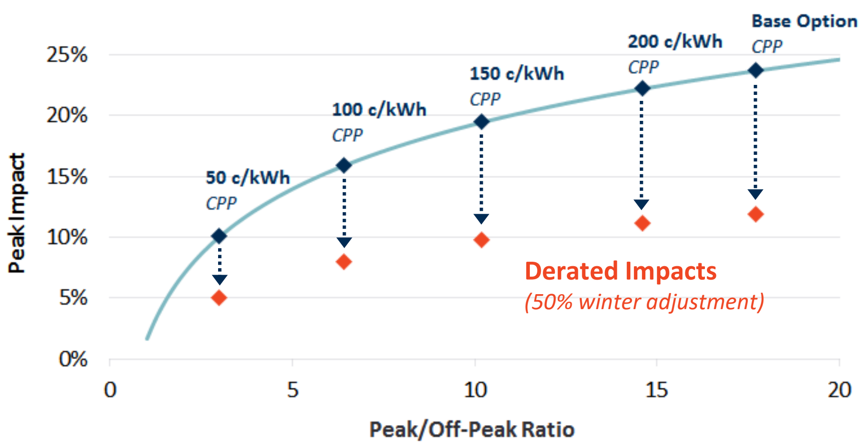
(assuming 15% participation)



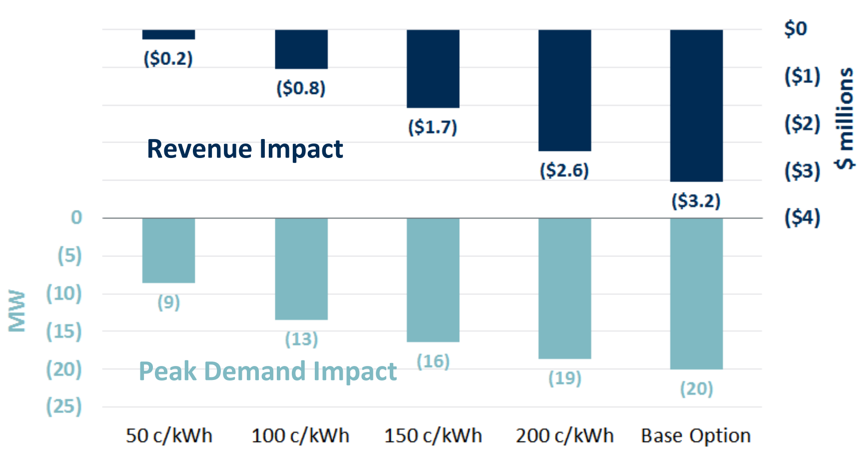
Notes: Peak reductions represent the estimated MW decrease for the entire Residential Non-ETS class in the maximum load hour by season, assuming a 15% participation rate. The SOR/CPP, TOU #3, TOU #4, and TOU/CPP #4 tariffs, which only model peak rates in CPP and/or Winter Peak hours, assume that usage remains unchanged in the rest of the year (Spring through Fall).

Residential Load Impacts
CPP and TOU 3B Sensitivities

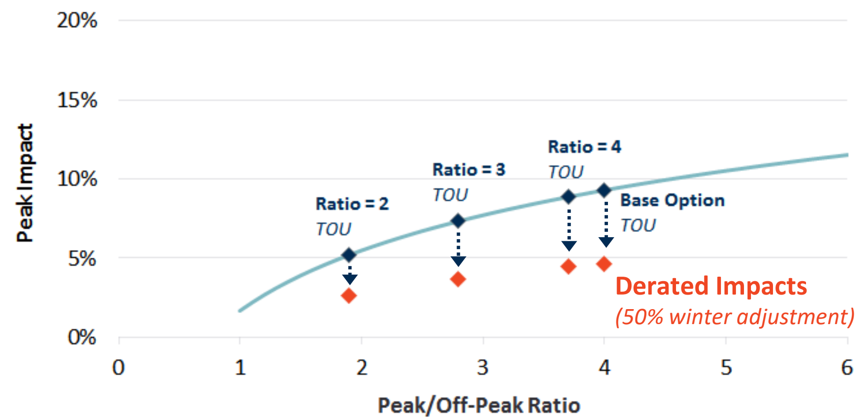
CPP Rate



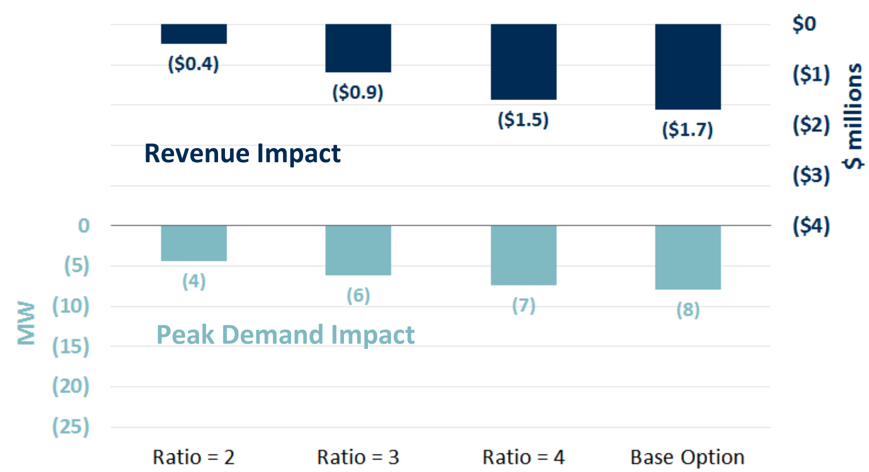
Notes Plotted ratios represent the all-in peak ratio, including a levelized fixed charge (computed as total fixed charge revenues over total kWh energy sales)



TOU Rate



Notes: Ratios in labels (Ratio = 2, Ratio = 3, Ratio = 4) represent the simple ratio of the peak to off-peak energy rates, while the actual ratios plotted represent the all-in ratio



SGS TVP Designs
Peak to Off-Peak (P/OP) Ratios

Customers respond by shifting their usage from higher priced hours to lower priced hours. Thus, the ratio of peak-to-off-peak (P/OP) prices is an important metric to gauge the expected load impact

- Based on the empirical evidence from the previous pilots, P/OP ratio would ideally be greater than 2 to incentivize some amount of load shifting
- If the ratio is greater (>=4), this will create a meaningful opportunity for customers to change their consumption patterns and achieve bill savings under new TVRs
- Nova Scotia Power TVRs have P/OP ratios 2.7 or greater, largely achieved by assigning the recovery of capacity costs during the peak hours

	Peak/Off-Peak Ratio			
	Winter	Spring & Fall	Summer	CPP
SOR				
SOR/CPP				23.1
TOU #1	3.1	2.7	2.9	
TOU #2	3.1	2.8	2.8	
TOU #3A	4.9			
TOU #3B	4.1			
TOU #4A	6.0			
TOU/CPP #4A	7.9			33.1
TOU #4B	5.1			
TOU/CPP #4B	6.3			33.1

Notes: Ratios shown are **all-in ratios** computed as (On-Peak c/kWh energy rate + Levelized Fixed Charge) / (Flat or Off-Peak c/kWh energy rate + Levelized Fixed Charge) in the same period. For the SOR/CPP, the Off-Peak rate is calculated as a weighted average of the first and second block flat rates.

SGS Load Impacts
% Peak Reduction (for an avg. SGS participant)

Using a regression fit to the Arcturus database, with binary variables for CPP vs. TOU rates, we estimated average peak impacts for a customer enrolled in each TVP rate proposed by Nova Scotia Power

- Given that the Arcturus database predominantly consists of residential summer-peaking utility pilots, we then apply a **50% derating factor** to adjust for lower customer response under a **winter-peaking utility** like NS Power
- We also apply an **additional 50% derating factor** to adjust for lower customer response from Small General Service customers, whose demand is **generally less elastic** than that of residential customers

	Implied Arc Impact		Impact After Derates	
	TOU	CPP	TOU	CPP
SOR/CPP		-24.8%		-6.2%
TOU #1	-7.6%		-1.9%	
TOU #2	-7.6%		-1.9%	
TOU #3A	-10.2%		-2.6%	
TOU #3B	-9.2%		-2.3%	
TOU #4A	-11.2%		-2.8%	
TOU/CPP #4A	-12.6%	-27.8%	-3.2%	-7.0%
TOU #4B	-10.4%		-2.6%	
TOU/CPP #4B	-11.4%	-27.8%	-2.9%	-7.0%

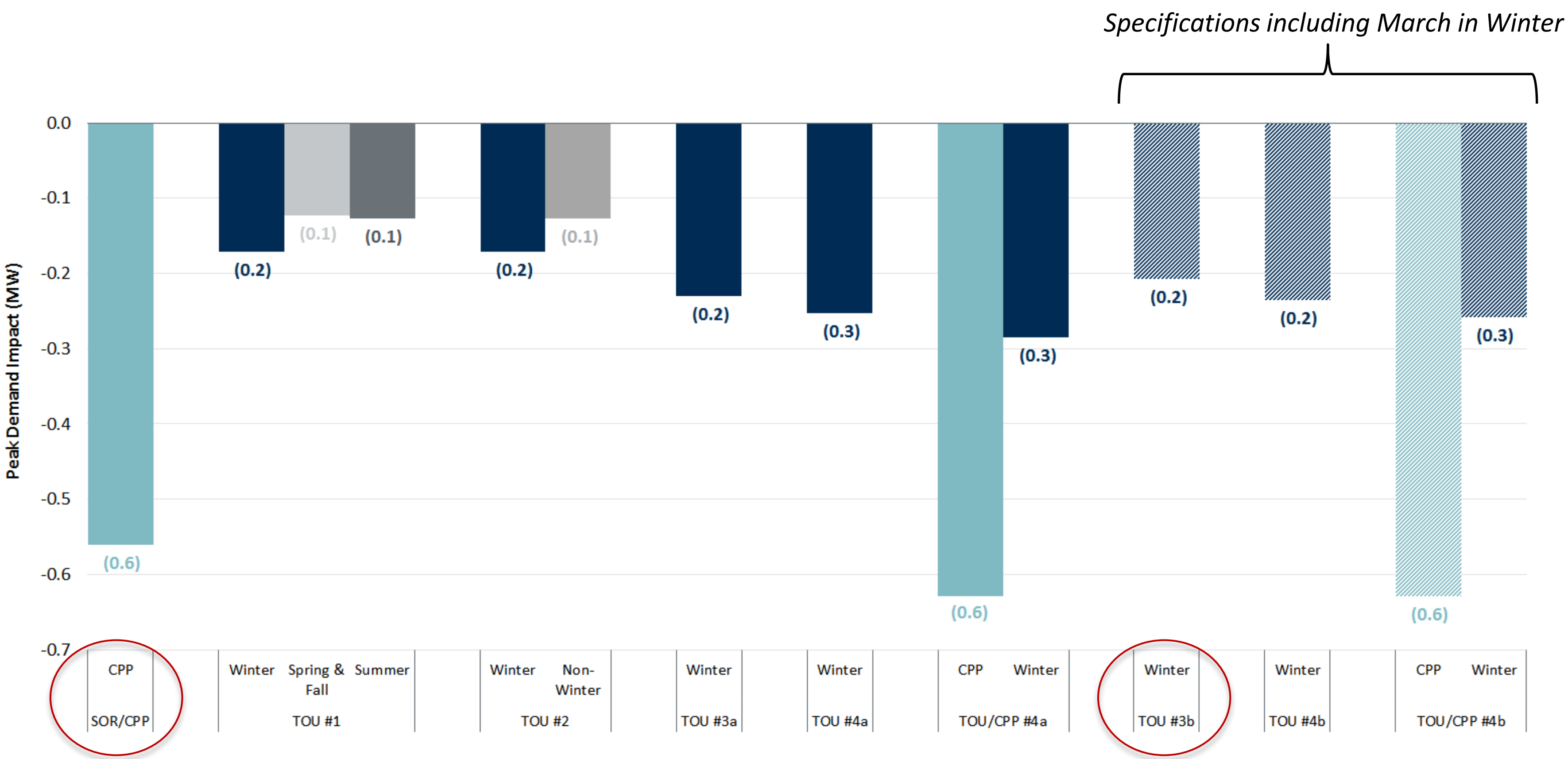
Notes: For TOU rates #1 and #2, TOU impacts shown represent per participant winter impacts. Ratios for proposed TVP rate designs represent all-in ratios, which consider a levelized fixed charge in both the on-peak and off-peak price.

By applying an assumed 15% participation rate to the adjusted per customer estimates, we then calculate the % change in the peak period usage for the entire Small General Service class (shown in the following slide)

SGS Load Impacts

Peak Demand Reduction (MW)

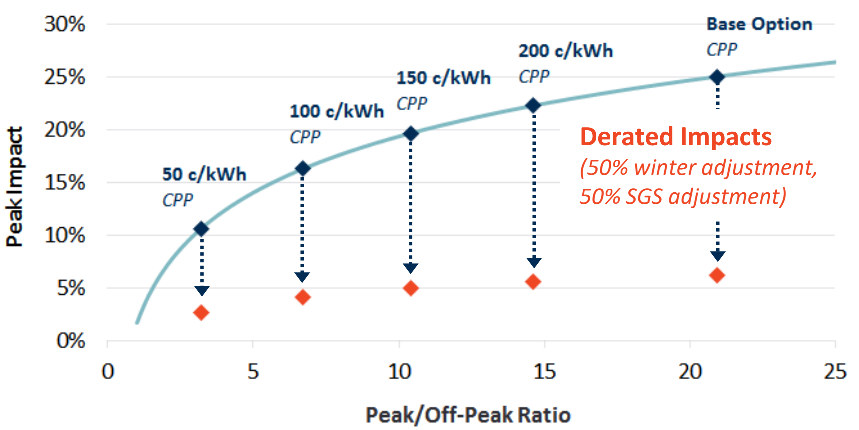
(assuming 15% participation)



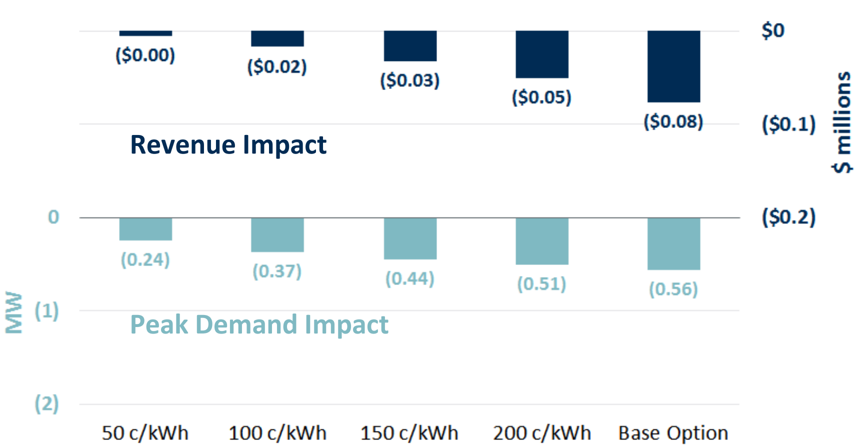
Notes: Peak reductions represent the estimated MW decrease for the entire Small General Service class in the maximum load hour by season, assuming a 15% participation rate. The SOR/CPP, TOU #3, TOU #4, and TOU/CPP #4 tariffs, which only model peak rates in CPP and/or Winter Peak hours, assume that usage remains unchanged in the rest of the year (Spring through Fall).

SGS Load Impacts
CPP and TOU 3B Sensitivities

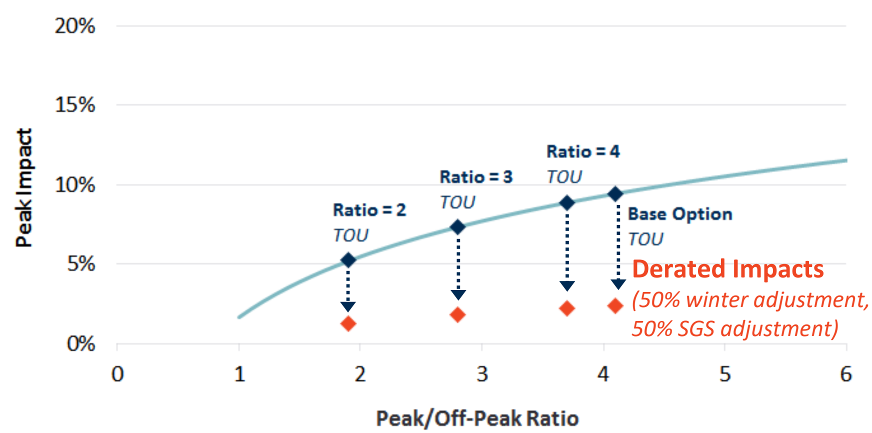
CPP Rate



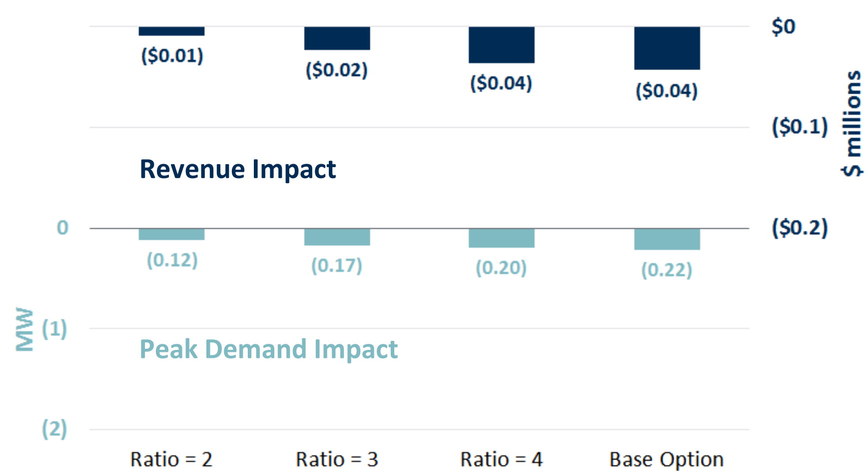
Notes Plotted ratios represent the all-in peak ratio, including a levelized fixed charge. Off-Peak rate is calculated as a weighted average of the first and second block flat rates.



TOU Rate



Notes: Ratios in labels (Ratio = 2, Ratio = 3, Ratio = 4) represent the simple ratio of the peak to off-peak energy rates, while the actual ratios plotted represent the all-in ratio.



GS TVP Designs
Peak to Off-Peak (P/OP) Ratios

Customers respond by shifting their usage from higher priced hours to lower priced hours. Thus, the ratio of peak-to-off-peak (P/OP) prices is an important metric to gauge the expected load impact

- Based on the empirical evidence from the previous pilots, P/OP ratio would ideally be greater than 2 to incentivize some amount of load shifting
- If the ratio is greater (>=4), this will create a meaningful opportunity for customers to change their consumption patterns and achieve bill savings under new TVRs
- Nova Scotia Power TVRs have P/OP ratios greater than 2, largely achieved by assigning the recovery of capacity costs during the peak hours

	Peak/Off-Peak Ratio			
	Winter	*Spring & Fall*	*Summer*	*CPP*
#0 SOR/CPP				21.3
#1 TOU	2.5	2.2	2.3	
#2 TOU	2.5	2.2	2.2	
#3A TOU	3.9			
#3B TOU	3.3			
#4A TOU	4.6			
#4A TOU/CPP	2.7			24.4
#4B TOU	3.9			
#4B TOU/CPP	2.3			24.4

Notes: Ratios shown are **all-in ratios** computed as (On-Peak c/kWh energy rate + Levelized Demand Charge) / (Flat or Off-Peak c/kWh energy rate + Levelized Demand Charge) in the same period. For the SOR/CPP, the Off-Peak rate is calculated as a weighted average of the first and second block flat rates.

GS Load Impacts
% Peak Reduction (for an avg. GS participant)

Using a regression fit to the Arcturus database, with binary variables for CPP vs. TOU rates, we estimated average peak impacts for a customer enrolled in each TVP rate proposed by Nova Scotia Power

- Given that the Arcturus database predominantly consists of residential summer-peaking utility pilots, we then apply a **50% derating factor** to adjust for lower customer response under a **winter-peaking utility** like NS Power

	Implied Arc Impact		Derated Arc Impact	
	TOU	*CPP*	*TOU*	*CPP*
#0 SOR/CPP		-25.1%		-12.6%
#1 TOU	-6.8%		-3.4%	
#2 TOU	-6.8%		-3.4%	
#3A TOU	-9.2%		-4.6%	
#3B TOU	-8.3%		-4.1%	
#4A TOU	-10.1%		-5.1%	
#4A TOU/CPP	-7.2%	-26.2%	-3.6%	-13.1%
#4B TOU	-9.2%		-4.6%	
#4B TOU/CPP	-6.3%	-26.2%	-3.1%	-13.1%

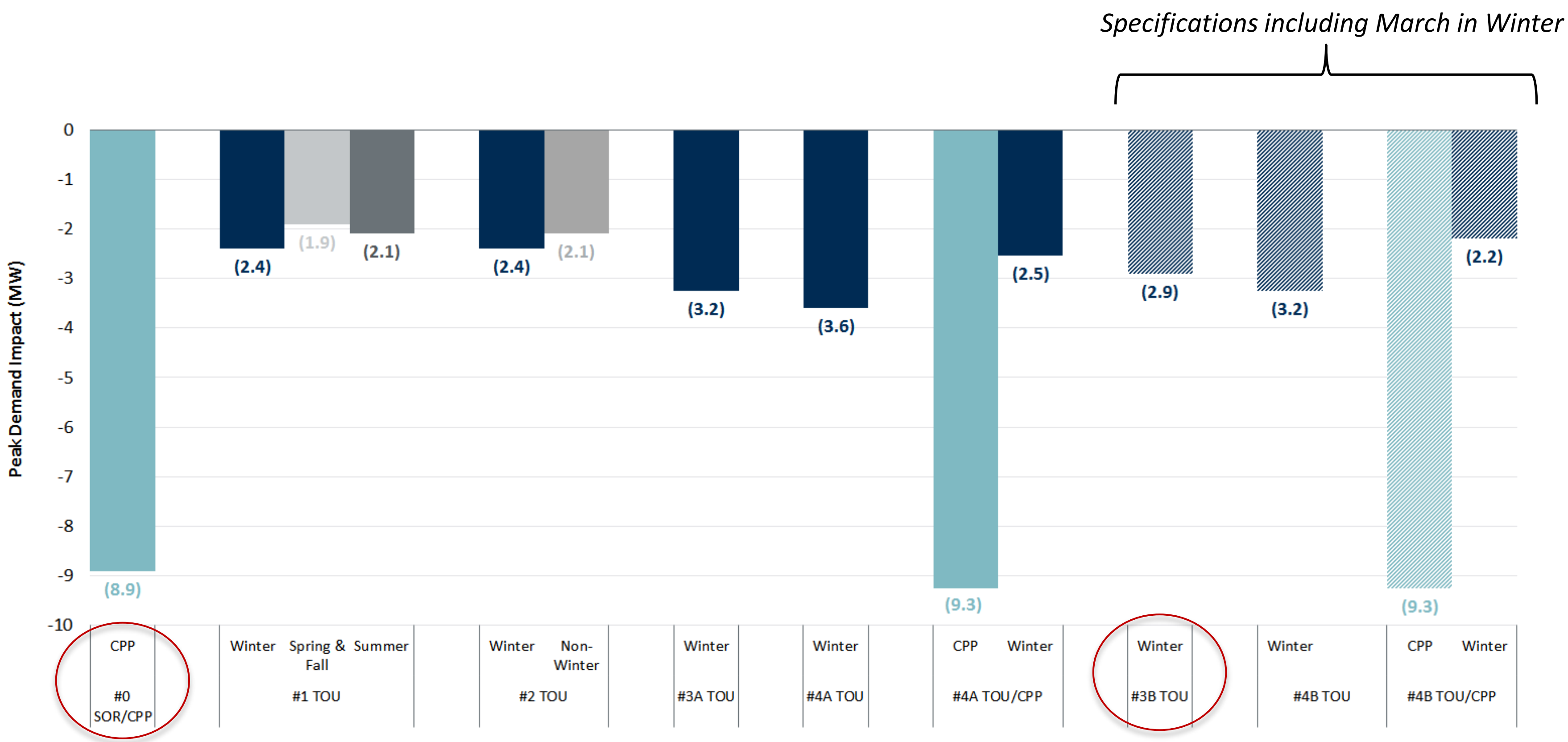
Notes: For TOU rates #1 and #2, TOU impacts shown represent per participant winter impacts. Ratios for proposed TVP rate designs represent all-in ratios, which consider a levelized demand charge in both the on-peak and off-peak price.

By applying an assumed 15% participation rate to the adjusted per customer estimates, we then calculate the % change in the peak period usage for the entire General Service class (shown in the following slide)

GS Load Impacts

Peak Demand Reduction (MW)

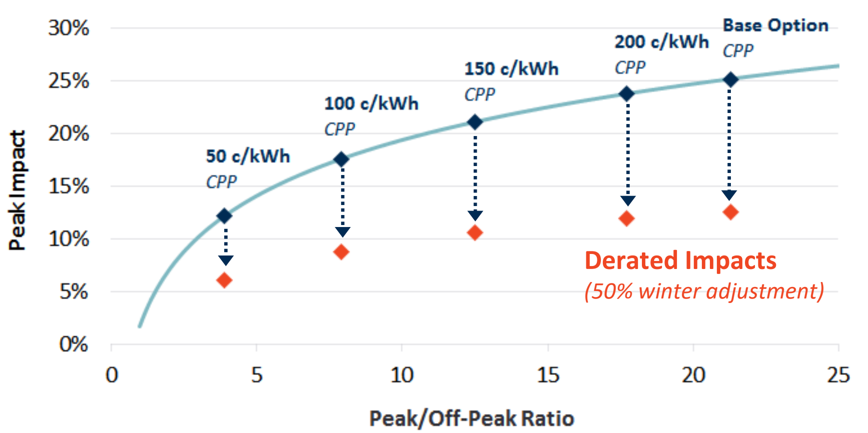
(assuming 15% participation)



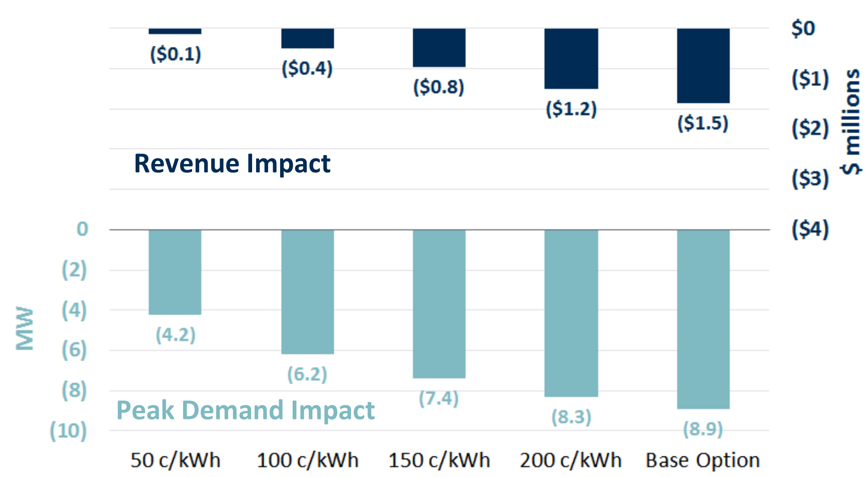
Notes: Peak reductions represent the estimated MW decrease for the entire General Service class in the maximum load hour by season, assuming a 15% participation rate. The SOR/CPP, TOU #3, TOU #4, and TOU/CPP #4 tariffs, which only model peak rates in CPP and/or Winter Peak hours, assume that usage remains unchanged in the rest of the year (Spring through Fall).

GS Load Impacts
CPP and TOU 3B Sensitivities

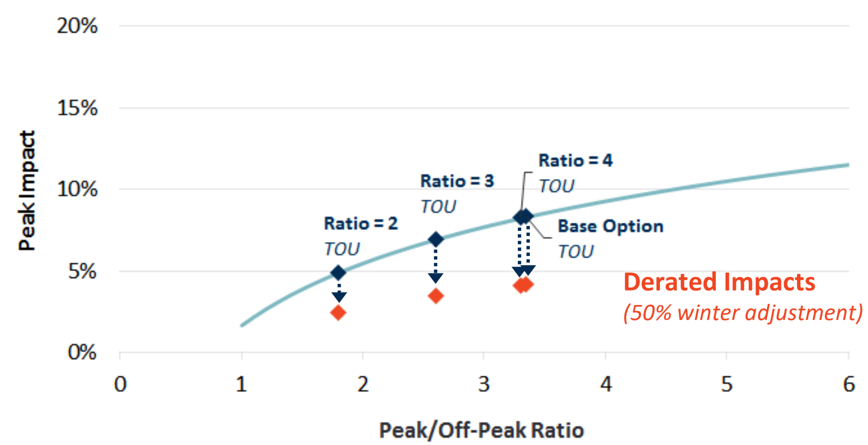
CPP Rate



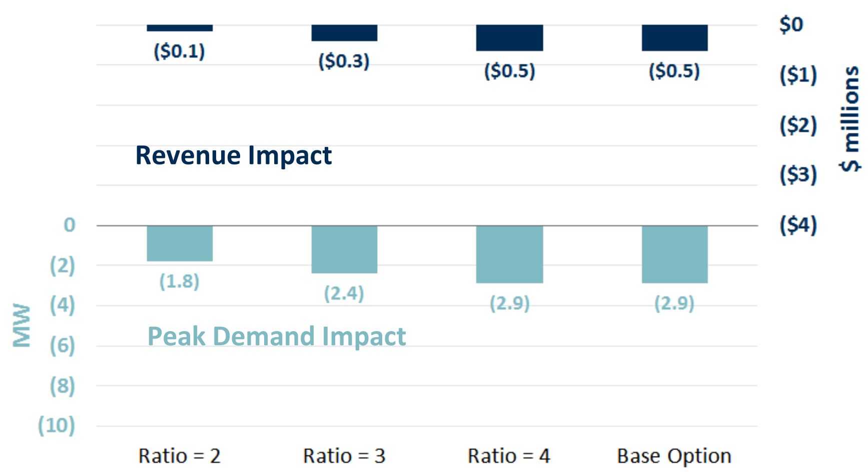
Notes Plotted ratios represent the all-in peak ratio, including a levelized demand charge. Off-Peak rate is calculated as a weighted average of the first and second block flat rates.



TOU Rate

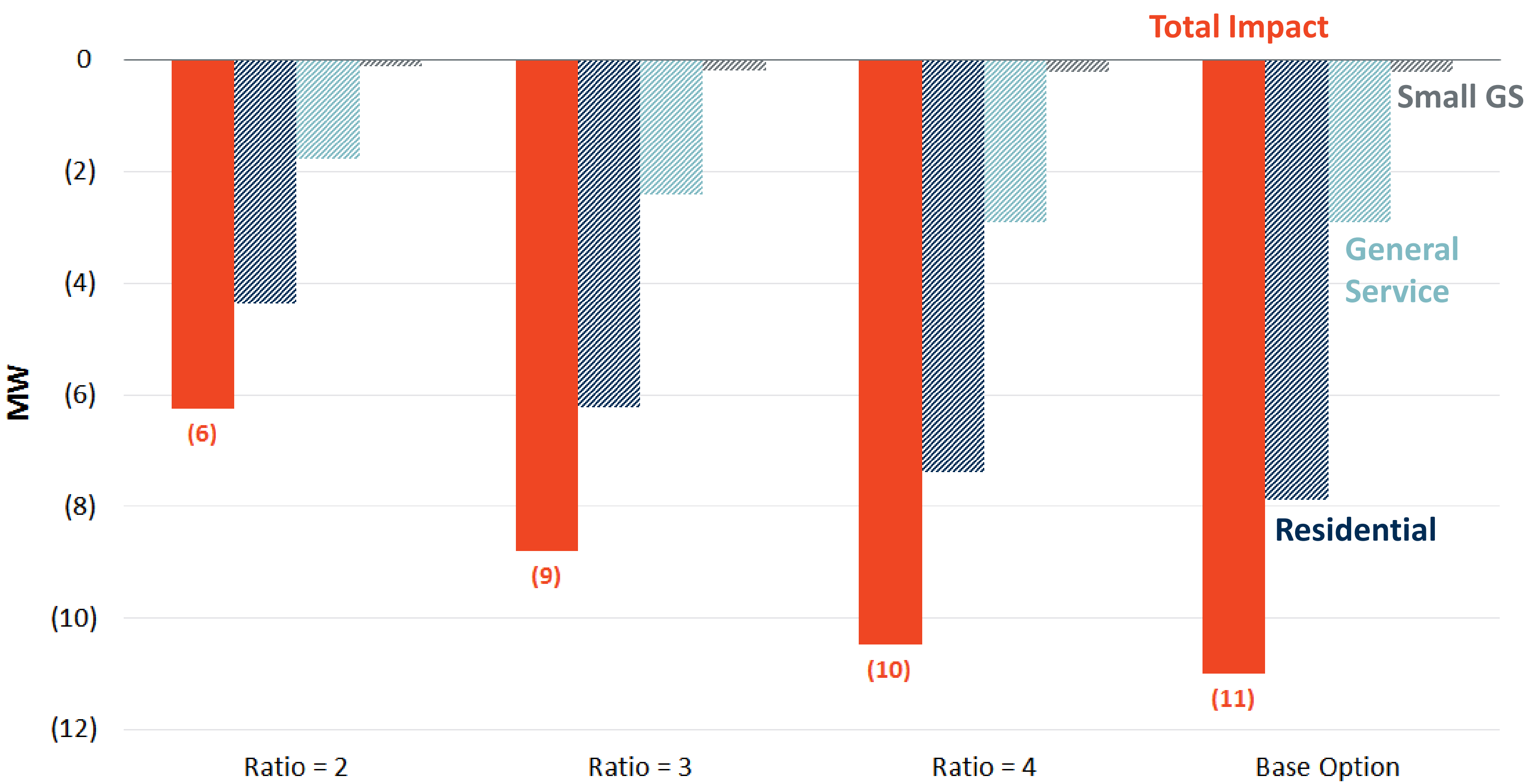


Notes: Ratios in labels (Ratio = 2, Ratio = 3, Ratio = 4) represent the simple ratio of the peak to off-peak energy rates, while the actual ratios plotted represent the all-in ratio



Load Impacts
TOU – Peak Demand Reduction (MW)

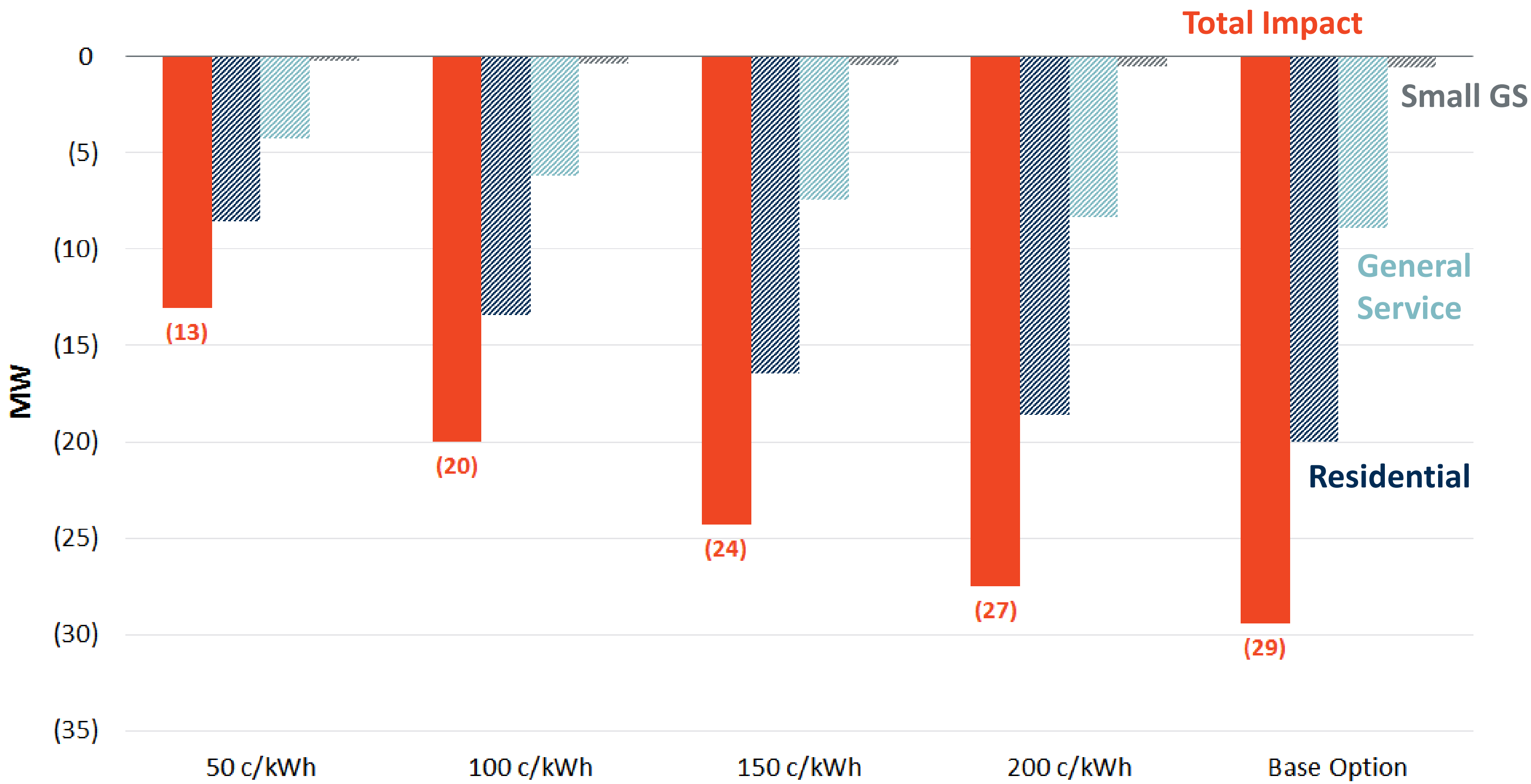
Across the three rate classes, the TOU tariffs have estimated capacity savings ranging from 6 to 11 MW, depending on the scale of the P/OP ratio



Notes: Peak reductions represent the estimated MW decrease in the maximum load hour by season, assuming a 15% participation rate.

Load Impacts
CPP – Peak Demand Reduction (MW)

Across the three rate classes, the CPP tariffs have estimated capacity savings ranging from 13 to 29 MW, depending on the size of the CPP rate



Notes: Peak reductions represent the estimated MW decrease in the maximum load hour by season, assuming a 15% participation rate.

Recommendations
Suggested TVP Ratios

After analyzing different price ratios and associated demand and earning impacts, **we conclude that targeting a 3:1 ratio for the TOU rate and 10:1 ratio for the CPP rate (~150 cents peak price)** might the proposed approach for the initial phase of the deployment for Nova Scotia Power

- Assuming these two rates are offered to customers and each rate successfully enrolls 15% of the customers (30% of each class participates in the TVR), **the total peak impact is 33 MW (24 MW from CPP and 9 MW from TOU)**
- If the participation turns out to be lower than expected, then there is still sufficient "buffer" to meet the 26 MW target price response embedded in the IRP

While increasing these ratios further increases the expected peak impacts, they may also widen the distribution of the bill impacts and may be less favorable from a customer experience perspective

Recommendations

Additional Rate Options

It is important to note that different TOU rates might be added to the menu in the future for incentivizing efficient use of electricity

- A rate design could be designed for EV owners; it will probably differ from the TOU rates in this deck
- A rate design for PV owners; it will probably differ from the TOU rates in this deck

Recommendations
Pilot Studies/Limited Deployment

It may be useful to pilot one or more of these rates or introduce them in a limited deployment construct (i.e. capping the number of participants during the first couple of years). This would allow testing of customer understanding, acceptance and load response to the new rates

Limited deployment may also allow testing of other innovative approaches such as behavioral messaging, inclusion of enabling technologies, and at some point testing the concept of automating demand response by getting prices to devices

Ultimately, NS Power should consider offering rate choices to customers but wrapping them around an innovative, customer-friendly but cost-reflective rate as the default

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Customer Bill Distributions and Utility Revenue Impacts of Proposed TVPs

ANALYSIS OF RESIDENTIAL (NON-ETS), SMALL GS, AND GS CLASSES

PRESENTED TO
NS Power

PRESENTED BY
Ahmad Faruqui
Sanem Sergici

June 2020

THE Brattle GROUP

These options vary in their simplicity and impact on peak demand and revenue

To strike a balance among these outcomes, NS Power has narrowed down the considered TVR options to the CPP/SOR and TOU #3B rates

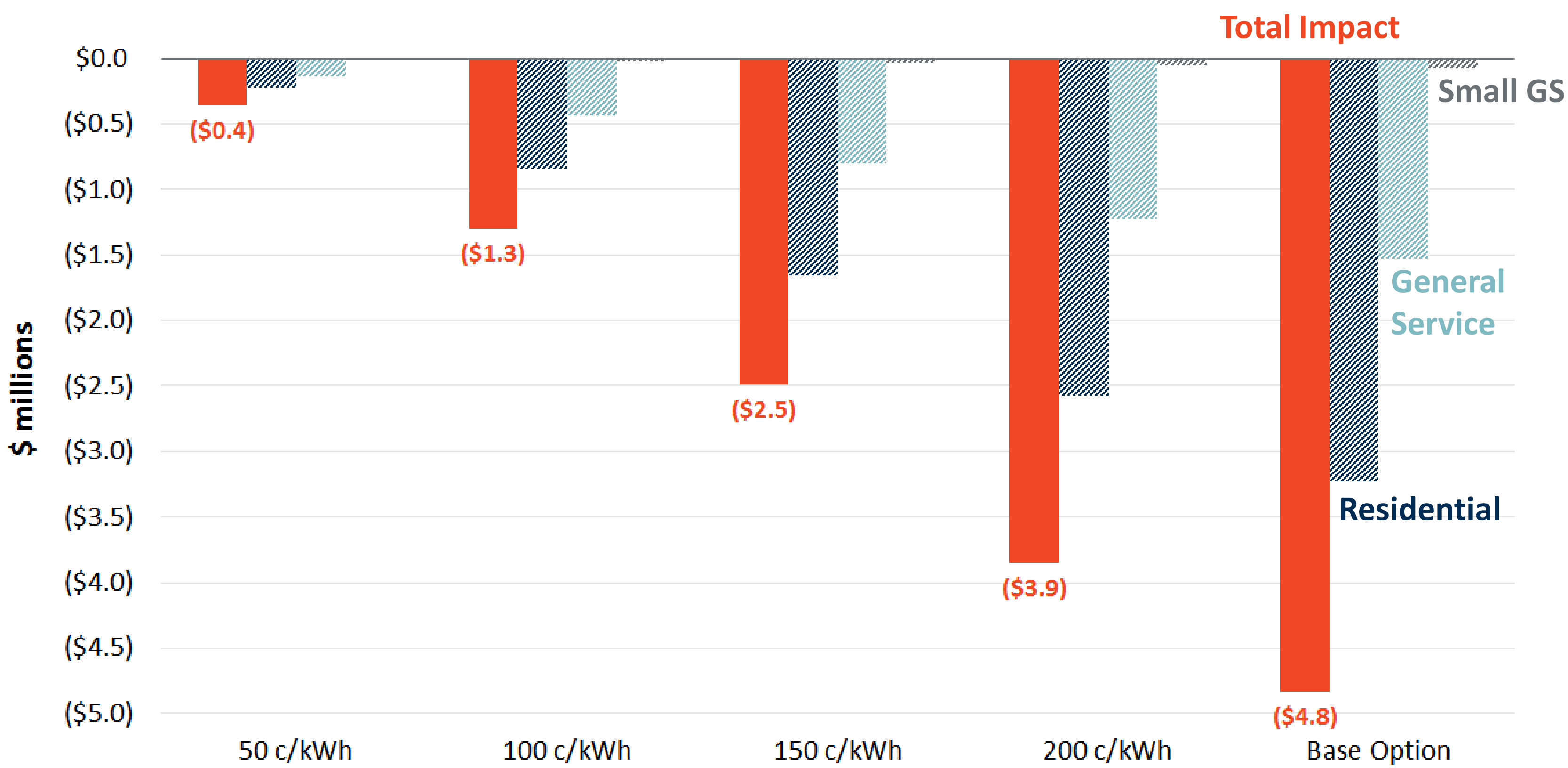
- The following slides refer to these selected rates as "CPP" and "TOU" respectively
- Table below present the total impacts from all three classes, assuming 15% participation from each class

	Rate Simplicity	Aggregate Peak Impact (MW)	Revenue Impact ($M)
TOU1	Low	10.0	2.1
TOU2	Low	10.0	2.1
TOU3A	Medium	12.0	2.5
TOU3B	Medium	11.0	2.3
TOU4A	High	13.4	3.0
TOU4B	High	12.4	2.8
TOU4A/CPP	Low	32.7	7.3
TOU4B/CPP	Low	32.7	7.1
CPP	High	29.4	4.8

Notes: For TOU1 and TOU2, Peak Load Impact shown represent winter impacts. Aggregate Peak Load Impact is calculated assuming 15% participation.

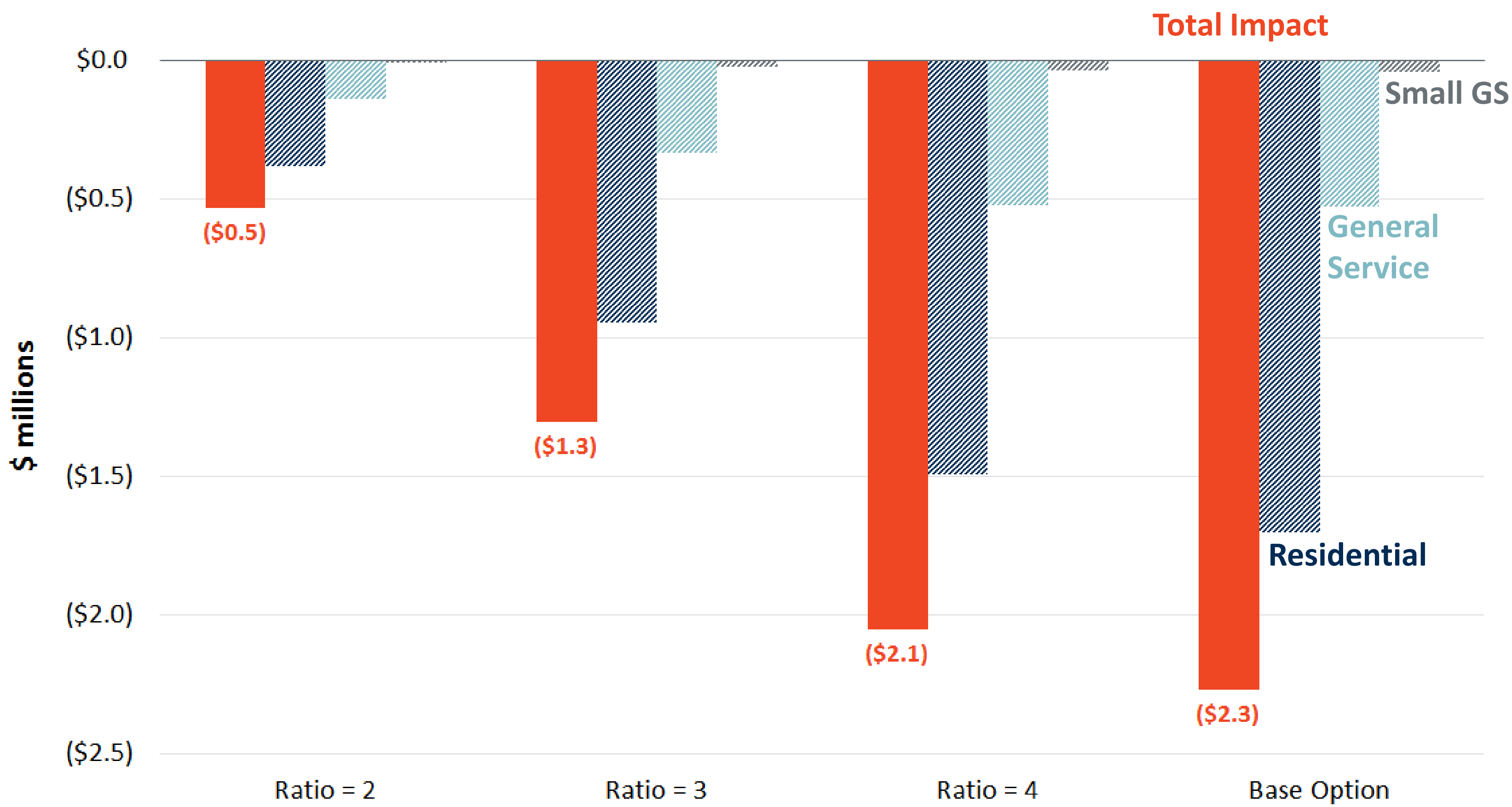
Estimated Impacts
CPP - Revenue Impact

Across the three rate classes, the CPP tariffs have estimated revenue impacts ranging from $0.4 to $4.8 million, depending on the size of the CPP rate



Estimated Impacts
TOU - Revenue Impact

Across the three rate classes, the TOU tariffs have estimated revenue impacts ranging from $0.5 to $2.3 million, depending on the scale of the P/OP ratio



Recommendations
Pilot Studies/Limited Deployment

It may be useful to pilot one or more of these rates or introduce them in a limited deployment construct (i.e. capping the number of participants during the first couple of years). This would allow testing of customer understanding, acceptance and load response to the new rates

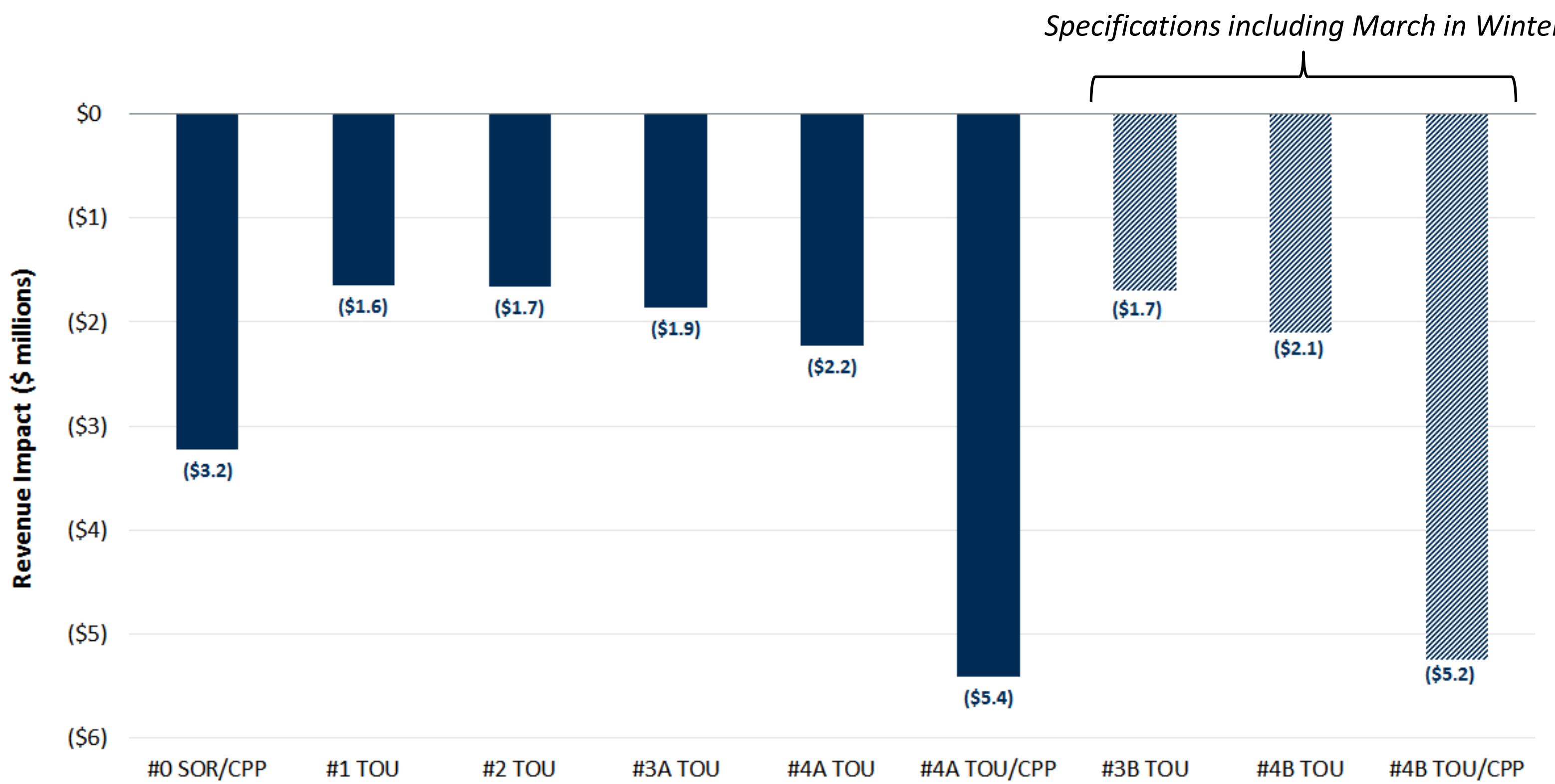
Limited deployment may also allow testing of other innovative approaches such as behavioral messaging, inclusion of enabling technologies, and at some point testing the concept of automating demand response by getting prices to devices

Ultimately, NS Power should consider offering rate choices to customers but wrapping them around an innovative, customer-friendly but cost-reflective rate as the default

Residential Class Revenue Impacts

Impact of TVP Rates on Revenue

Revenue impacts range from 0.25% (under TOU1 and TOU2) to 0.8% (under TOU/CPP4) assuming 15% customer participation



Residential Bill Impacts
Methodology I

For nine of the proposed rate options, we prepared bill impact distributions for 135 residential customers in NS Power's 2019 residential load research sample

- The sample consists of 59 customers with electric heat (Rate Code 3) and 76 customers without electric heat (Rate Code 2)
  - Customers in the sample without electric heat have an average monthly usage of 845 kWh and an average annual bill of $1,775
  - Customers in the sample with electric heat have an average monthly usage of 1,413 kWh and an average annual bill of $2,880
- The analysis defines the **peak period** as hours ending 8-11 AM and 5-8 PM in winter, 8 AM-noon in Spring & Fall, and 1-7 PM in summer
  - The **CPP period** is defined as the top 88 load hours in the year according to NS Power's system load. Of these 88 hours, 40 occur in January, 47 in February, and 1 in March

Residential Bill Impacts
Methodology II

Each customer's bill impact is computed using 2022 pricing options as:

Total annual bill under the new Time-Varying Rate *minus*

Total annual bill under the flat Standard Offer Rate

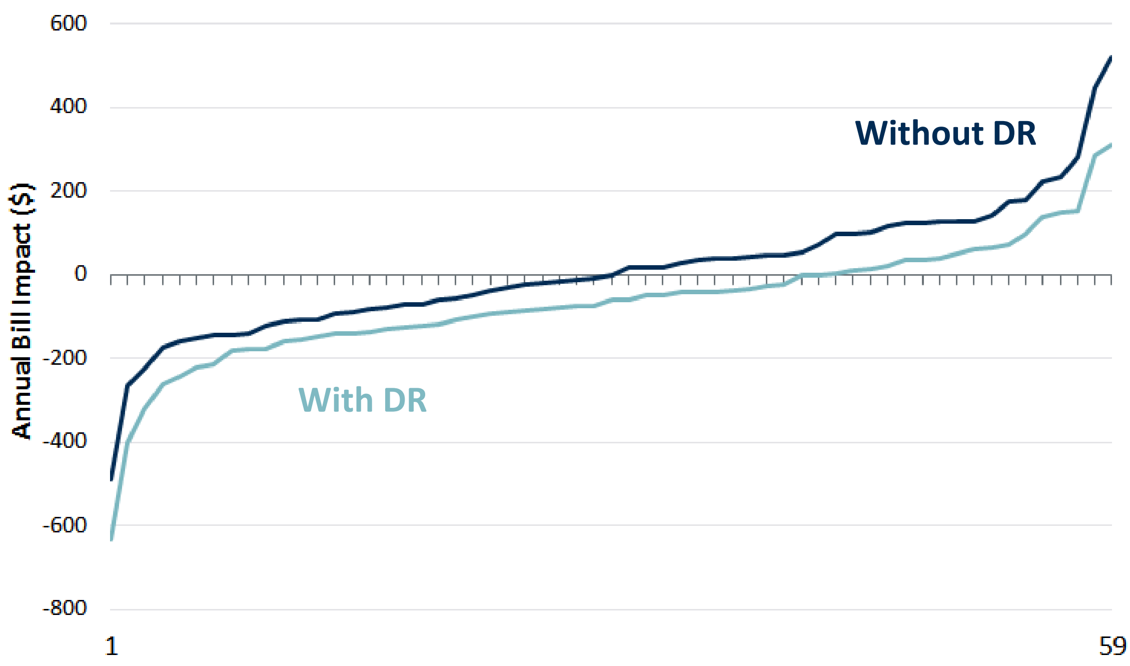
Bill impacts are computed both with and without demand response (DR) for each rate

- **Without DR**, bills are calculated assuming each customer's monthly peak and off-peak usage remain constant, with no load shifting between periods
- **With DR**, bills are calculated assuming customers shift usage from peak to off-peak hours (however no conservation is assumed)

Residential Bill Impacts
CPP/SOR, with Electric Heat

Under the CPP/SOR rate, 51% of electric heat customers experience *lower bills* without demand response compared to 69% with demand response

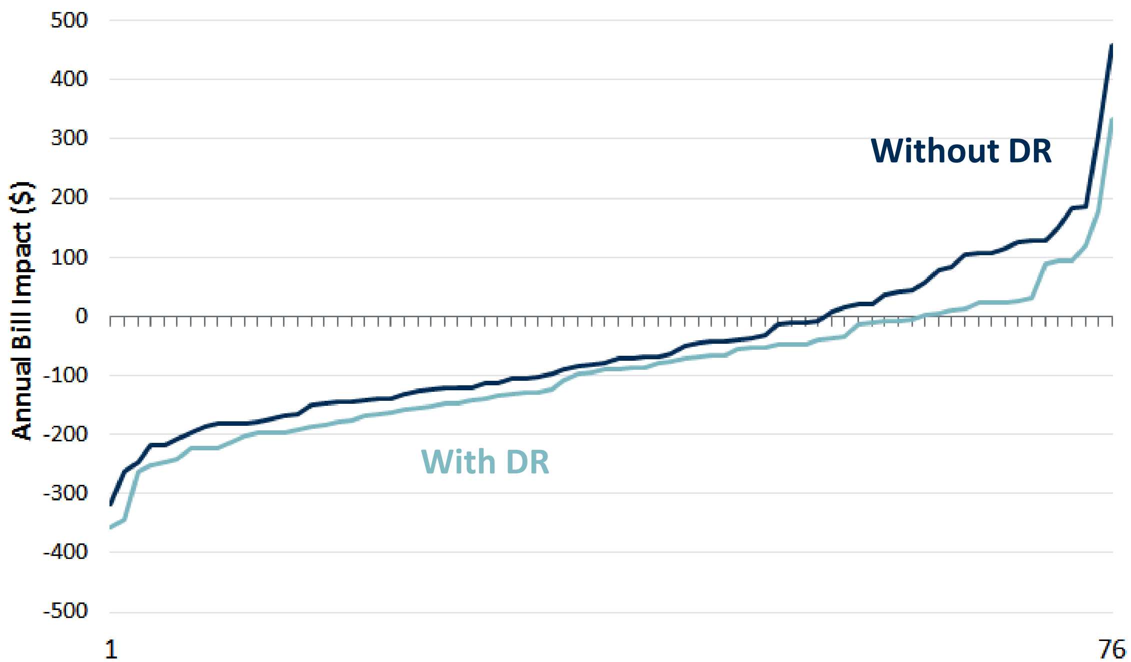
- Without DR, there is an average annual bill reduction of $105 and an average annual bill increase of $128, with an overall average bill impact of **$9**
- With DR, there is an average bill reduction of $133 and an average bill increase of $85, with an overall average bill impact of **-$67**



Residential Bill Impacts
CPP/SOR, without Electric Heat

Under the CPP/SOR rate, 71% of non-electric heat customers experience *lower bills* without demand response compared to 80% with demand response

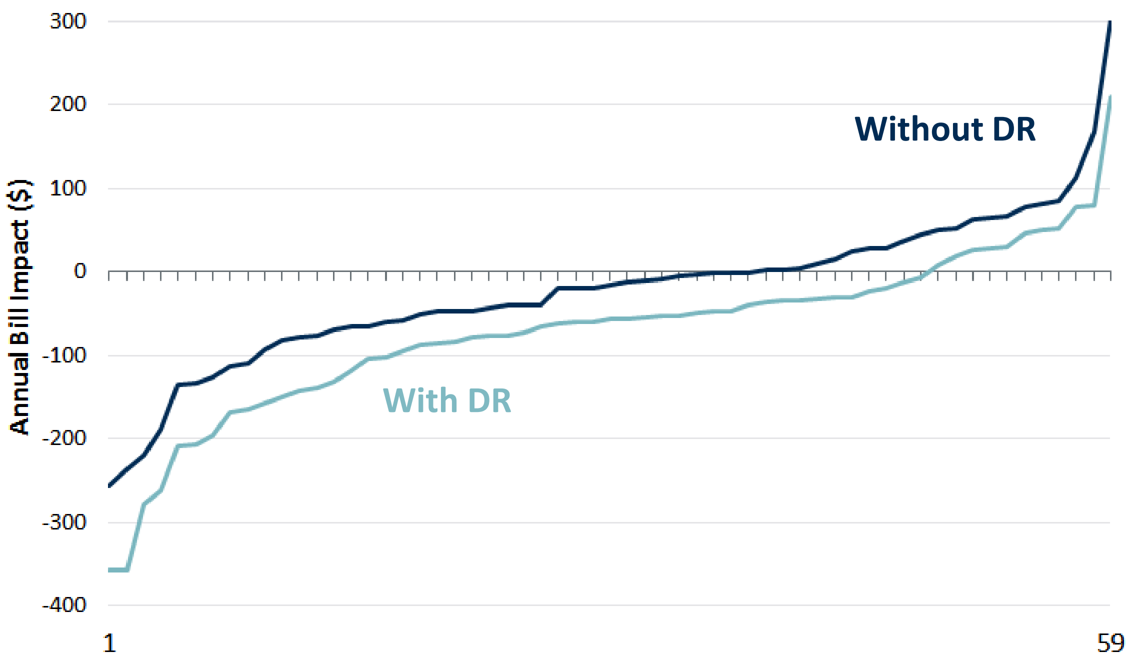
- Without DR, there is an average bill reduction of $120 and an average bill increase of $114, with an overall average bill impact of **-$52**
- With DR, there is an average bill reduction of $132 and an average bill increase of $71, with an overall average bill impact of **-$92**



Residential Bill Impacts
TOU #1, with Electric Heat

Under the TOU #1 rate, 64% of electric heat customers experience *lower bills* without demand response compared to 81% with demand response

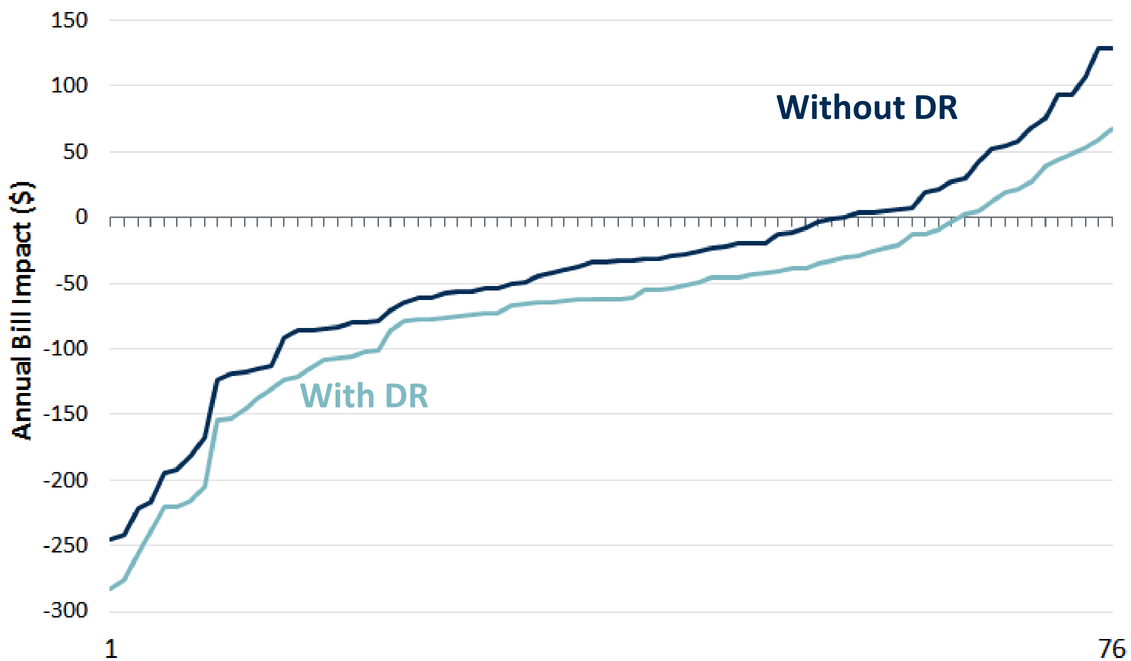
- Without DR, there is an average bill reduction of $70 and an average bill increase of $63, with an overall average bill impact of **-$23**
- With DR, there is an average bill reduction of $102 and an average bill increase of $57, with an overall average bill impact of **-$72**



Residential Bill Impacts
TOU #1, without Electric Heat

Under the TOU #1 rate, 72% of non-electric heat customers experience *lower bills* without demand response compared to 84% with demand response

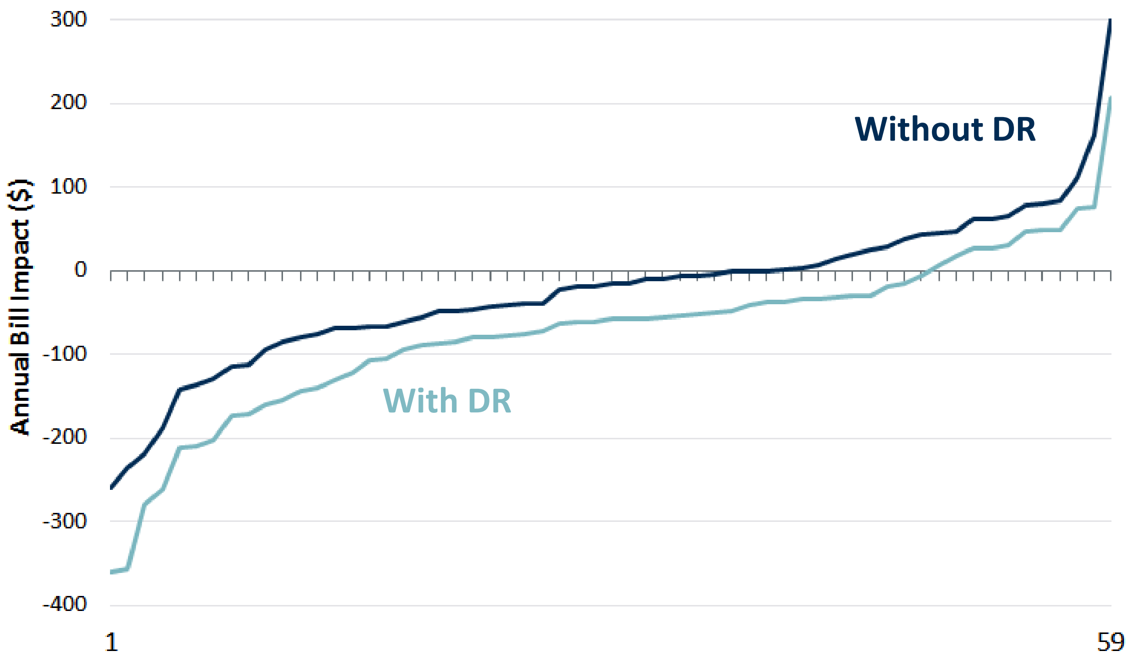
- Without DR, there is an average bill reduction of $75 and an average bill increase of $49, with an overall average bill impact of **-$41**
- With DR, there is an average bill reduction of $89 and an average bill increase of $33, with an overall average bill impact of **-$70**



Residential Bill Impacts
TOU #2, with Electric Heat

Under the TOU #2 rate, 66% of electric heat customers experience *lower bills* without demand response compared to 81% with demand response

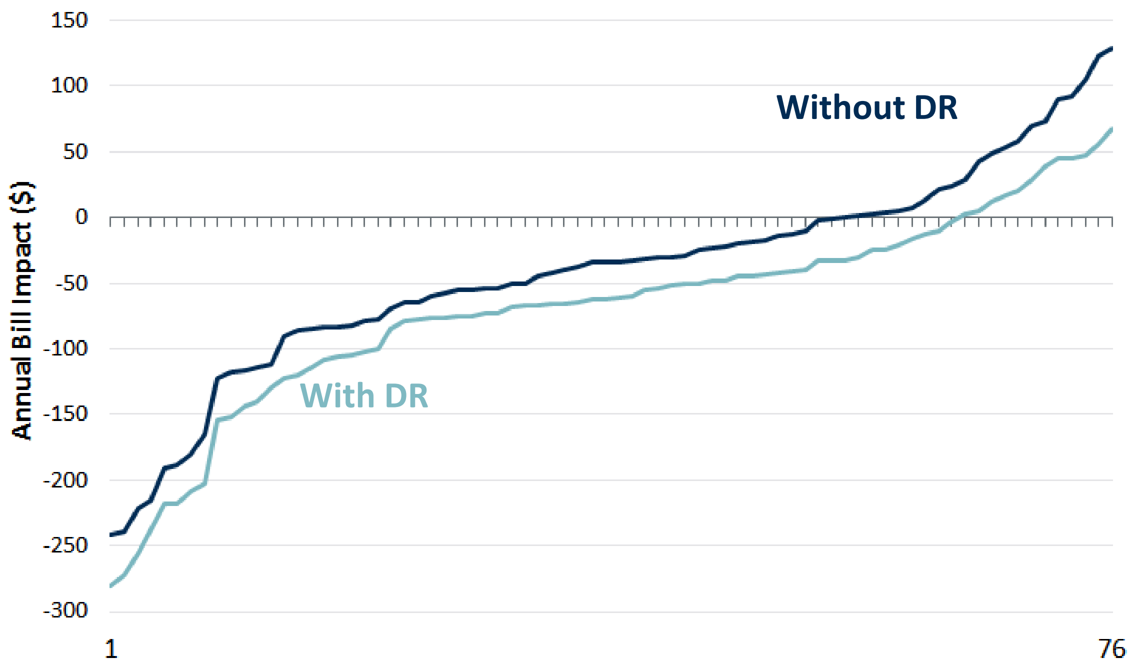
- Without DR, there is an average bill reduction of $69 and an average bill increase of $64, with an overall average bill impact of **-$24**
- With DR, there is an average bill reduction of $104 and an average bill increase of $55, with an overall average bill impact of **-$74**



Residential Bill Impacts
TOU #2, without Electric Heat

Under the TOU #2 rate, 72% of non-electric heat customers experience *lower bills* without demand response compared to 84% with demand response

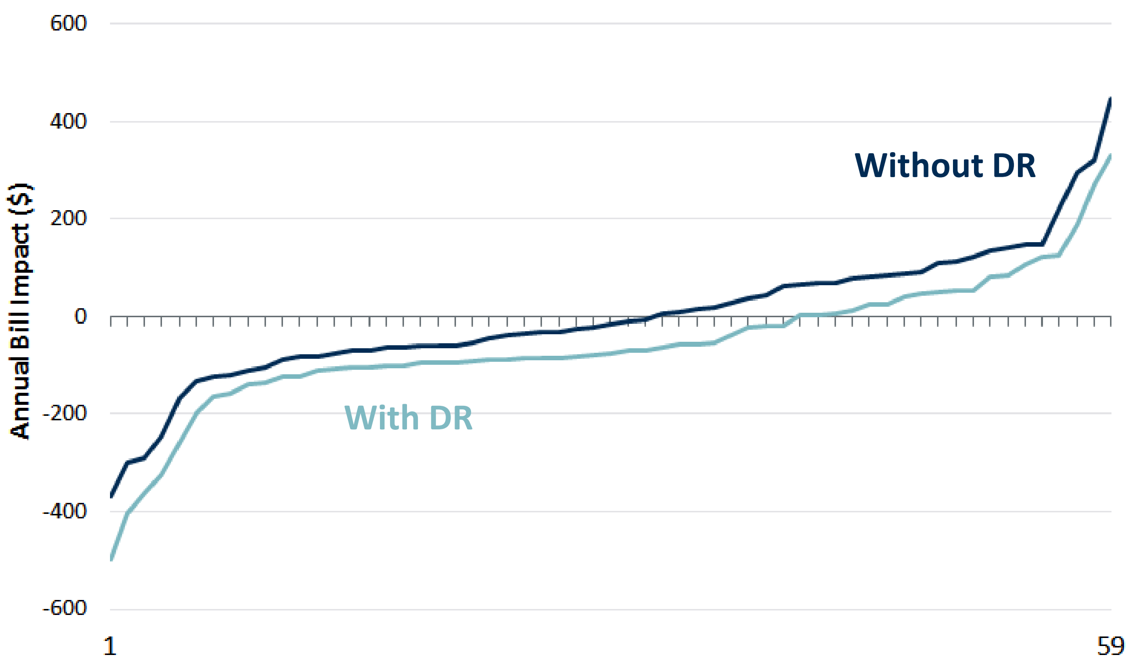
- Without DR, there is an average bill reduction of $75 and an average bill increase of $47, with an overall average bill impact of **-$41**
- With DR, there is an average bill reduction of $89 and an average bill increase of $32, with an overall average bill impact of **-$70**



Residential Bill Impacts
TOU #3A, with Electric Heat

Under the TOU #3A rate, 54% of electric heat customers experience *lower bills* without demand response compared to 68% with demand response

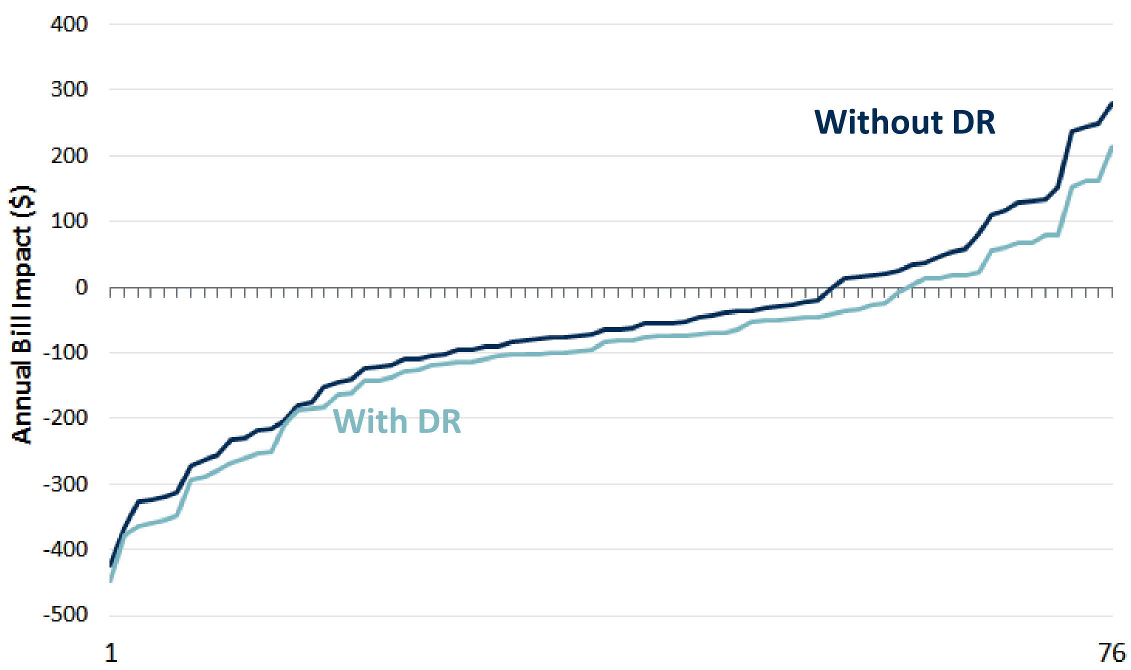
- Without DR, there is an average bill reduction of $96 and an average bill increase of $113, with an overall average bill impact of **$0**
- With DR, there is an average bill reduction of $126 and an average bill increase of $85, with an overall average bill impact of **-$58**



Residential Bill Impacts
TOU #3A, without Electric Heat

Under the TOU #3A rate, 71% of non-electric heat customers experience *lower bills* without demand response compared to 79% with demand response

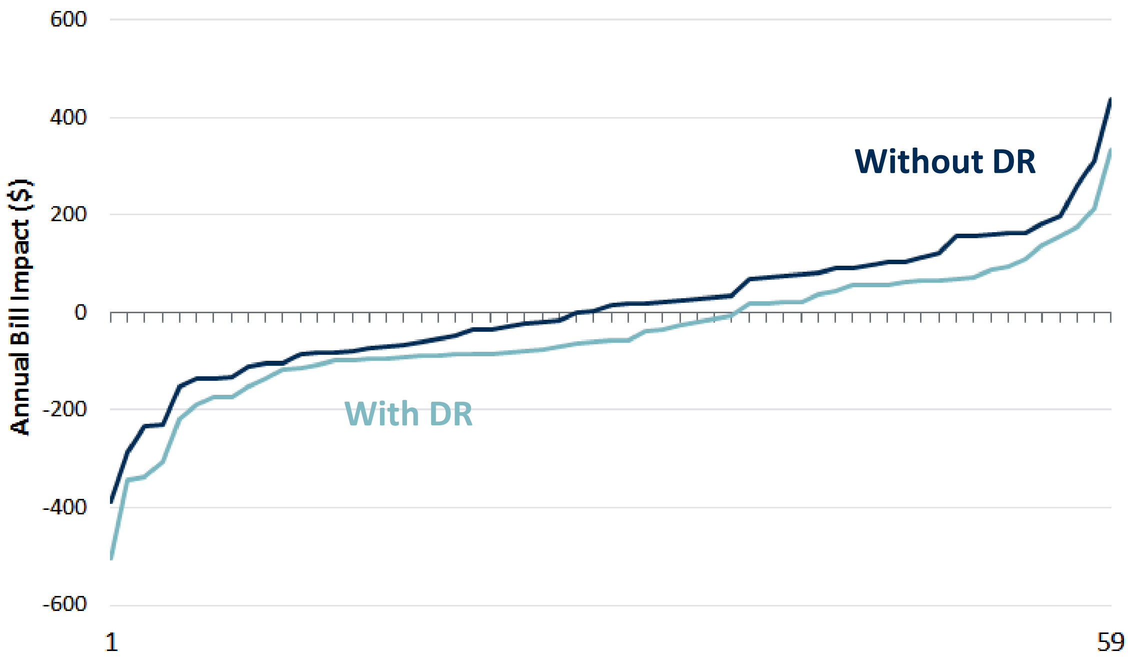
- Without DR, there is an average bill reduction of $133 and an average bill increase of $99, with an overall average bill impact of **-$66**
- With DR, there is an average bill reduction of $143 and an average bill increase of $74, with an overall average bill impact of **-$97**



Residential Bill Impacts
TOU #3B, with Electric Heat

Under the TOU #3B rate, 47% of electric heat customers experience *lower bills* without demand response compared to 63% with demand response

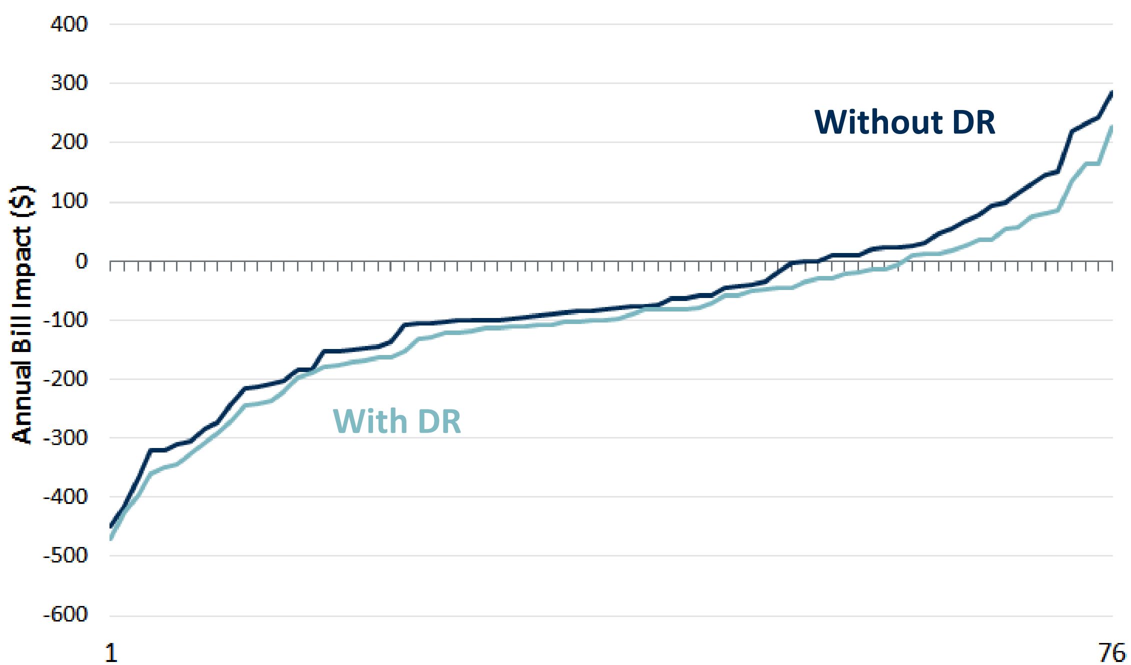
- Without DR, there is an average bill reduction of $102 and an average bill increase of $112, with an overall average bill impact of **$10**
- With DR, there is an average bill reduction of $121 and an average bill increase of $90, with an overall average bill impact of **-$42**



Residential Bill Impacts
TOU #3B, without Electric Heat

Under the TOU #3B rate, 70% of non-electric heat customers experience *lower bills* without demand response compared to 89% with demand response

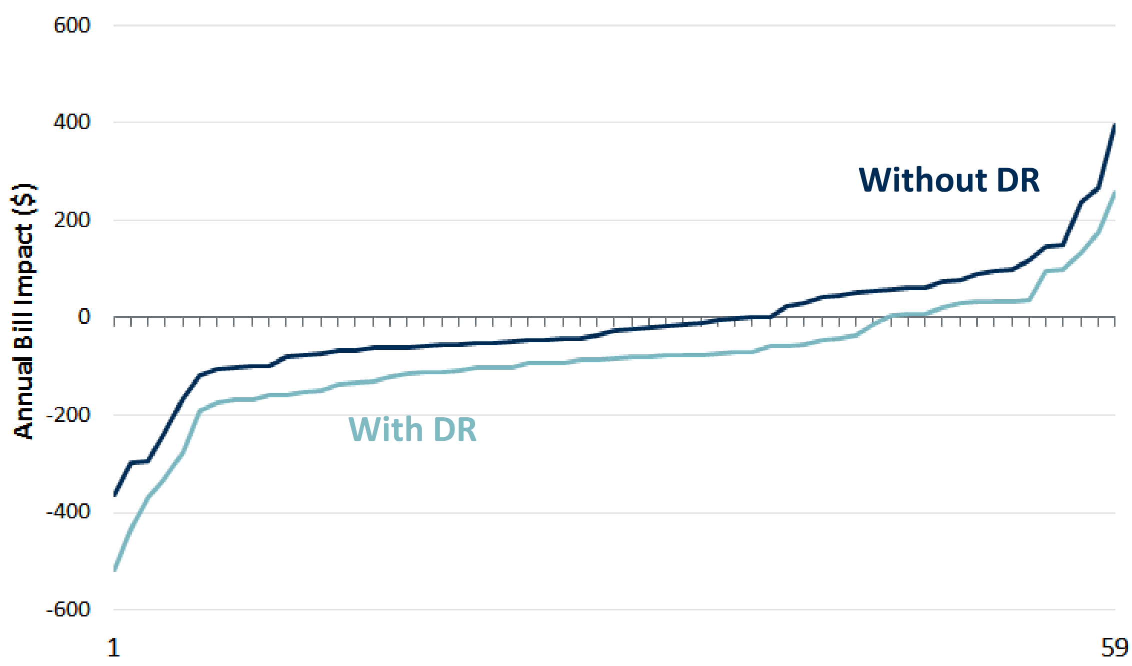
- Without DR, there is an average bill reduction of $145 and an average bill increase of $92, with an overall average bill impact of **-$73**
- With DR, there is an average bill reduction of $148 and an average bill increase of $75, with an overall average bill impact of **-$101**



Residential Bill Impacts
TOU #4A, with Electric Heat

Under the TOU #4A rate, 63% of electric heat customers experience *lower bills* without demand response compared to 76% with demand response

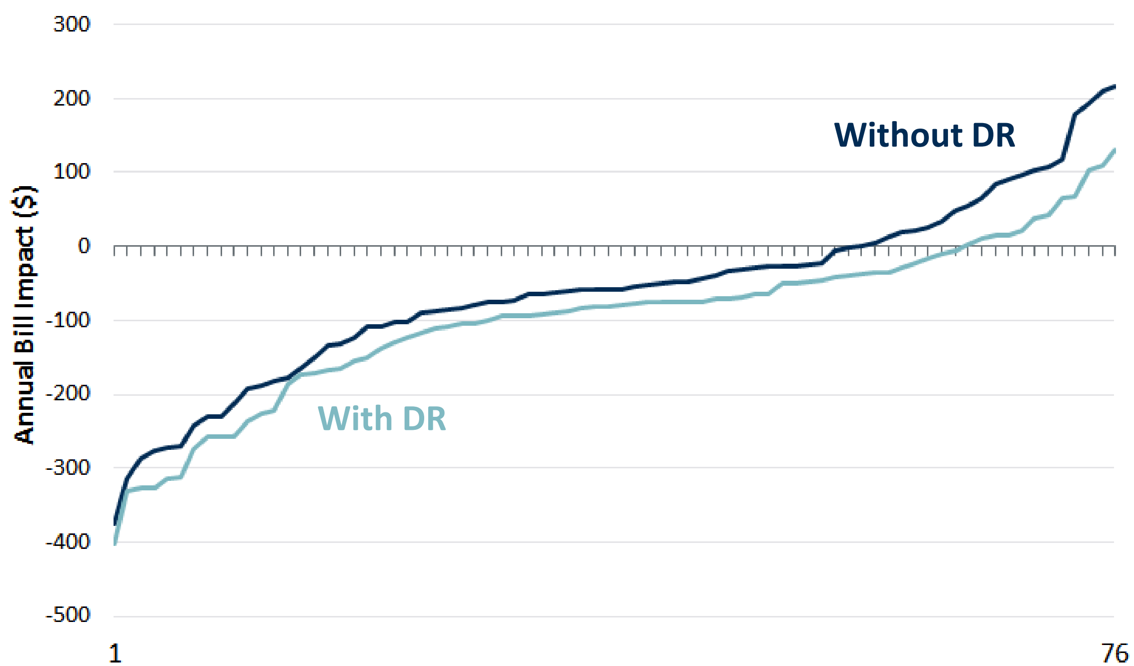
- Without DR, there is an average bill reduction of $84 and an average bill increase of $99, with an overall average bill impact of **-$16**
- With DR, there is an average bill reduction of $133 and an average bill increase of $69, with an overall average bill impact of **-$85**



Residential Bill Impacts
TOU #4A, without Electric Heat

Under the TOU #4A rate, 74% of non-electric heat customers experience *lower bills* without demand response compared to 93% with demand response

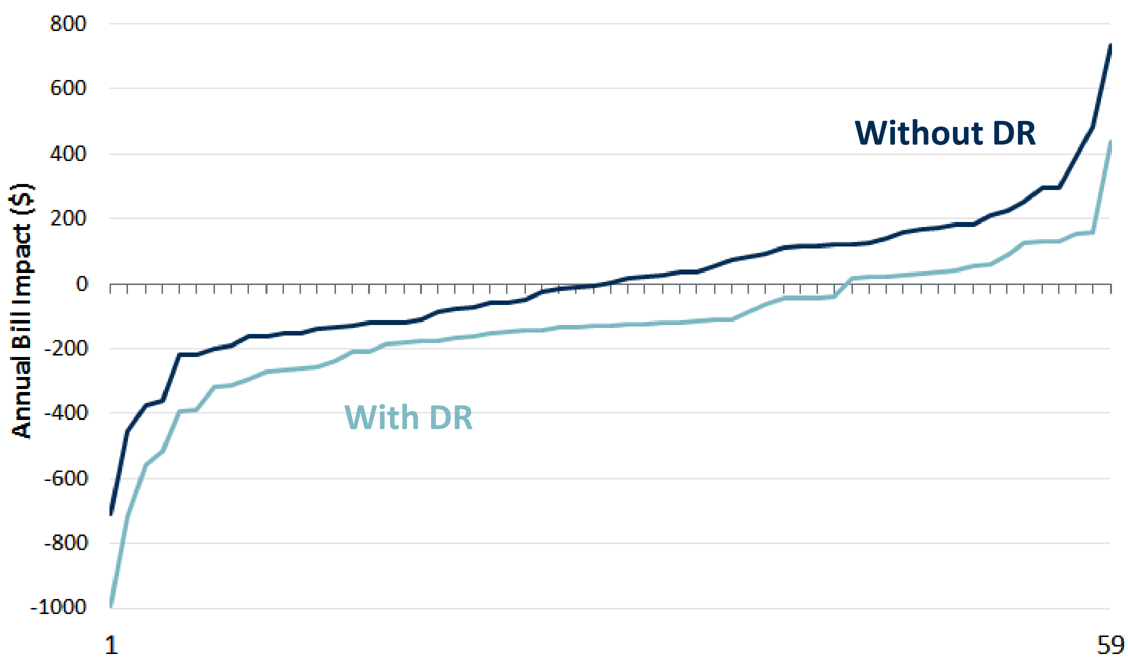
- Without DR, there is an average bill reduction of $112 and an average bill increase of $84, with an overall average bill impact of **-$60**
- With DR, there is an average bill reduction of $144 and an average bill increase of $18, with an overall average bill impact of **-$133**



Residential Bill Impacts
TOU/CPP #4A, with Electric Heat

Under the TOU/CPP #4A rate, 49% of electric heat customers experience lower bills without demand response compared to 73% with demand response

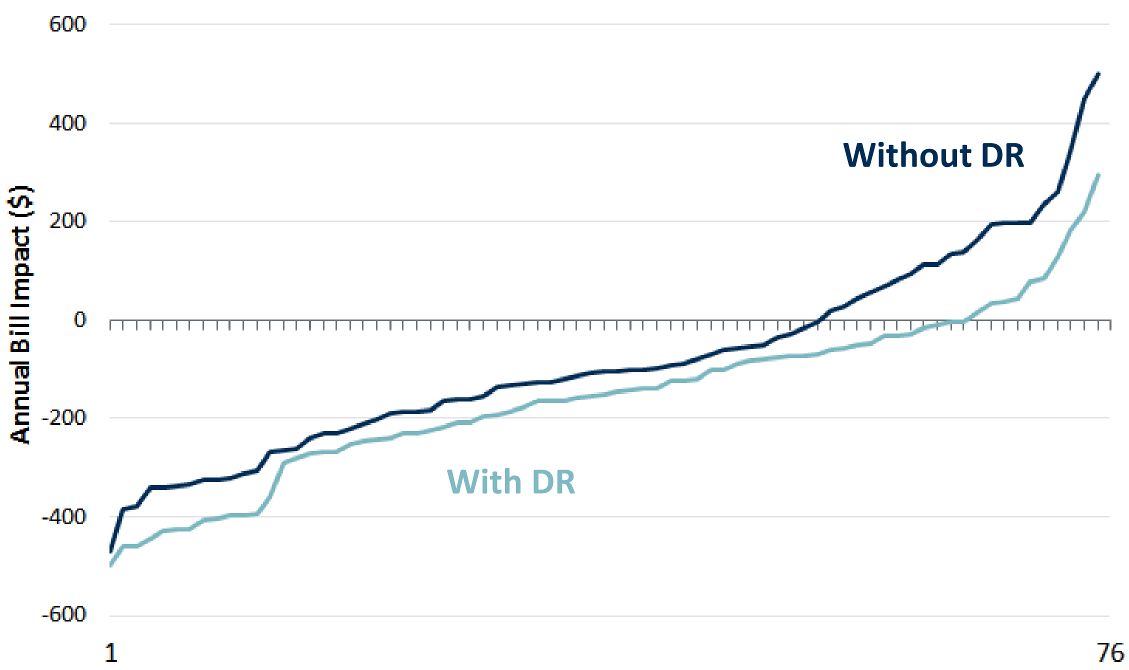
- Without DR, there is an average bill reduction of $161 and an average bill increase of $168, with an overall average bill impact of **$6**
- With DR, there is an average bill reduction of $221 and a single bill increase of $96, with an overall average bill impact of **-$135**



Residential Bill Impacts
TOU/CPP #4A, without Electric Heat

Under the TOU/CPP #4A rate, 72% of non-electric heat customers experience *lower bills* without demand response compared to 87% with demand response

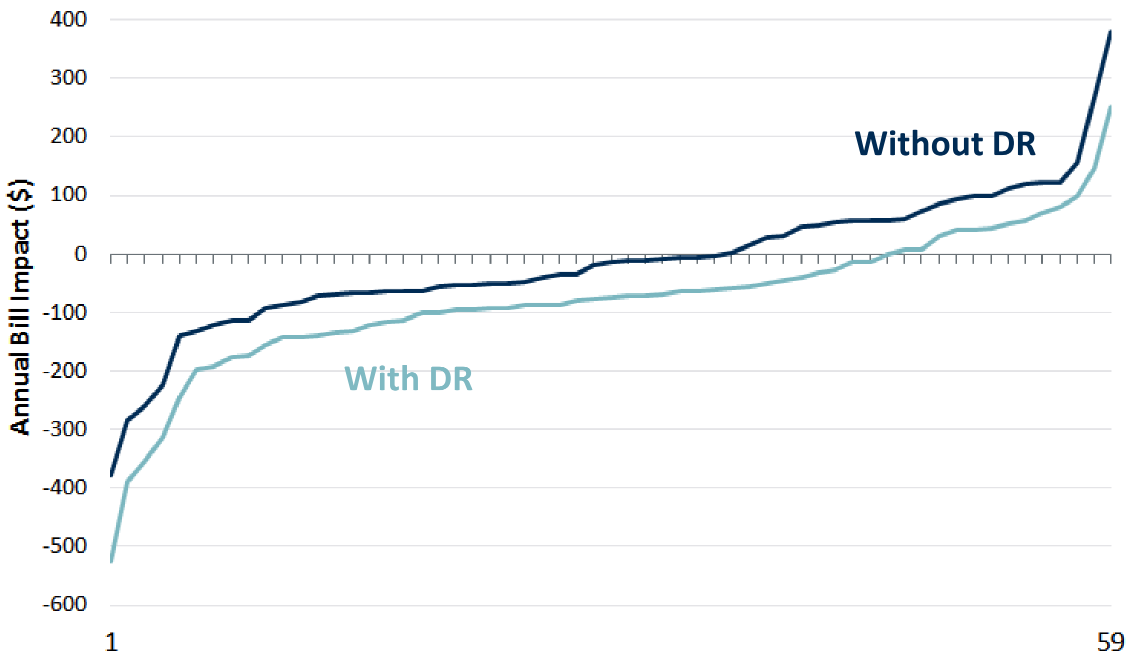
- Without DR, there is an average bill reduction of $189 and an average bill increase of $173, with an overall average bill impact of **-$89**
- With DR, there is an average bill reduction of $205 and an average bill increase of $112, with an overall average bill impact of **-$164**



Residential Bill Impacts
TOU #4B, with Electric Heat

Under the TOU #4B rate, 61% of electric heat customers experience *lower bills* without demand response compared to 78% with demand response

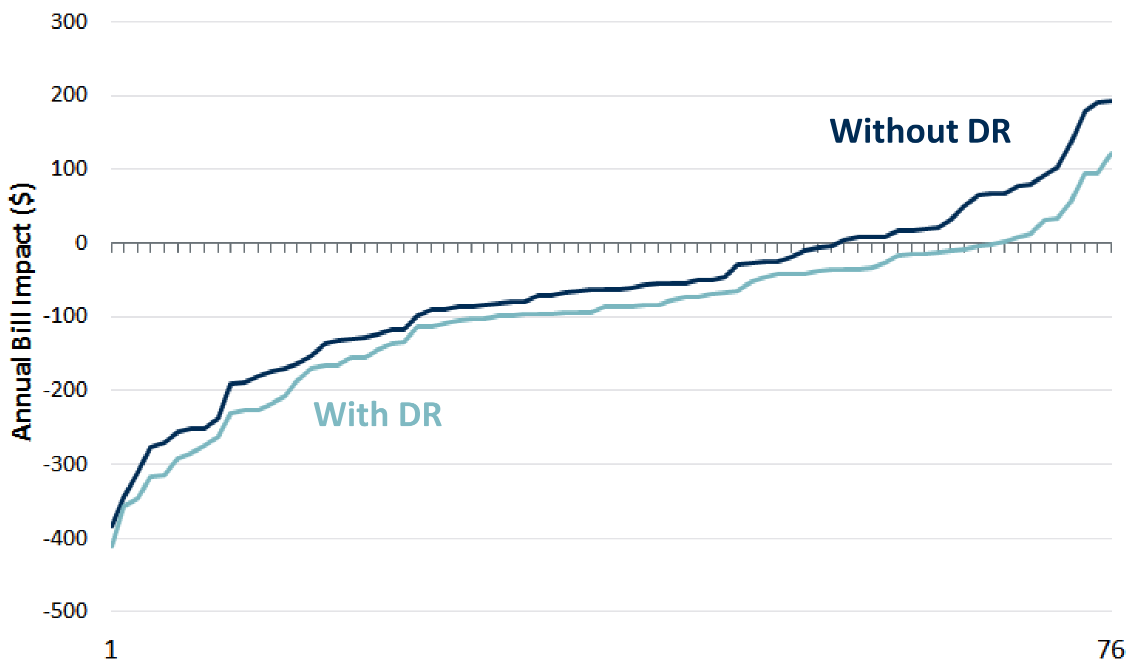
- Without DR, there is an average bill reduction of $83 and an average bill increase of $95, with an overall average bill impact of **-$14**
- With DR, there is an average bill reduction of $121 and an average bill increase of $71, with an overall average bill impact of **-$79**



Residential Bill Impacts
TOU #4B, without Electric Heat

Under the TOU #4B rate, 72% of non-electric heat customers experience *lower bills* without demand response compared to 88% with demand response

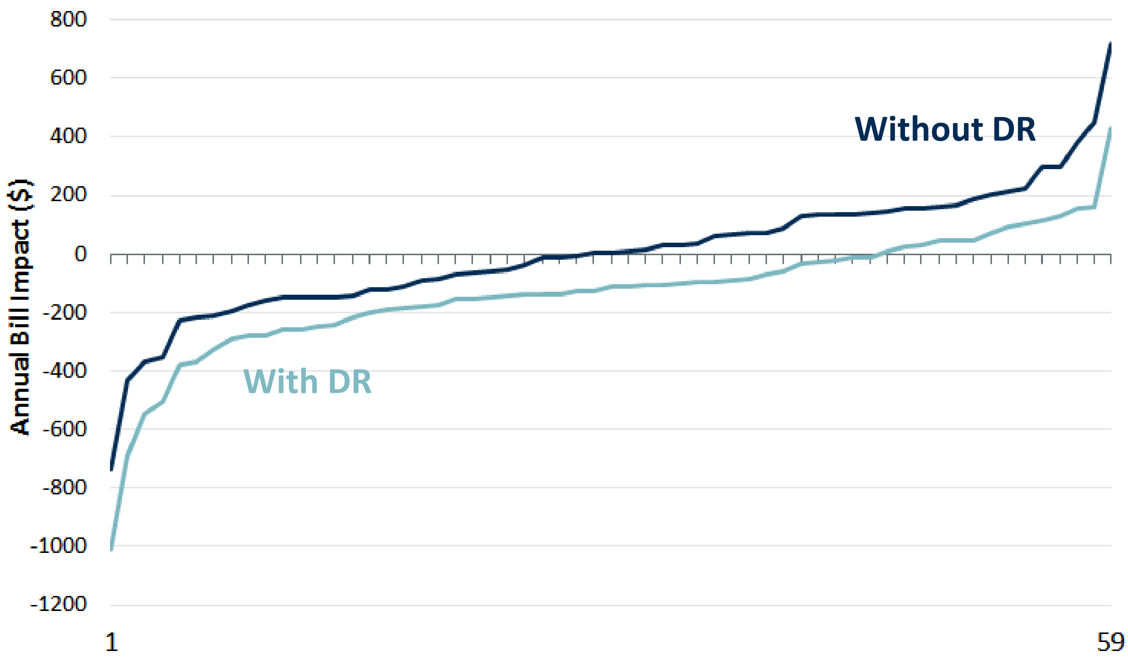
- Without DR, there is an average bill reduction of $118 and an average bill increase of $68, with an overall average bill impact of **-$67**
- With DR, there is an average bill reduction of $122 and an average bill increase of $50, with an overall average bill impact of **-$102**



Residential Bill Impacts
TOU/CPP #4B, with Electric Heat

Under the TOU/CPP #4B rate, 47% of electric heat customers experience lower bills without demand response compared to 76% with demand response

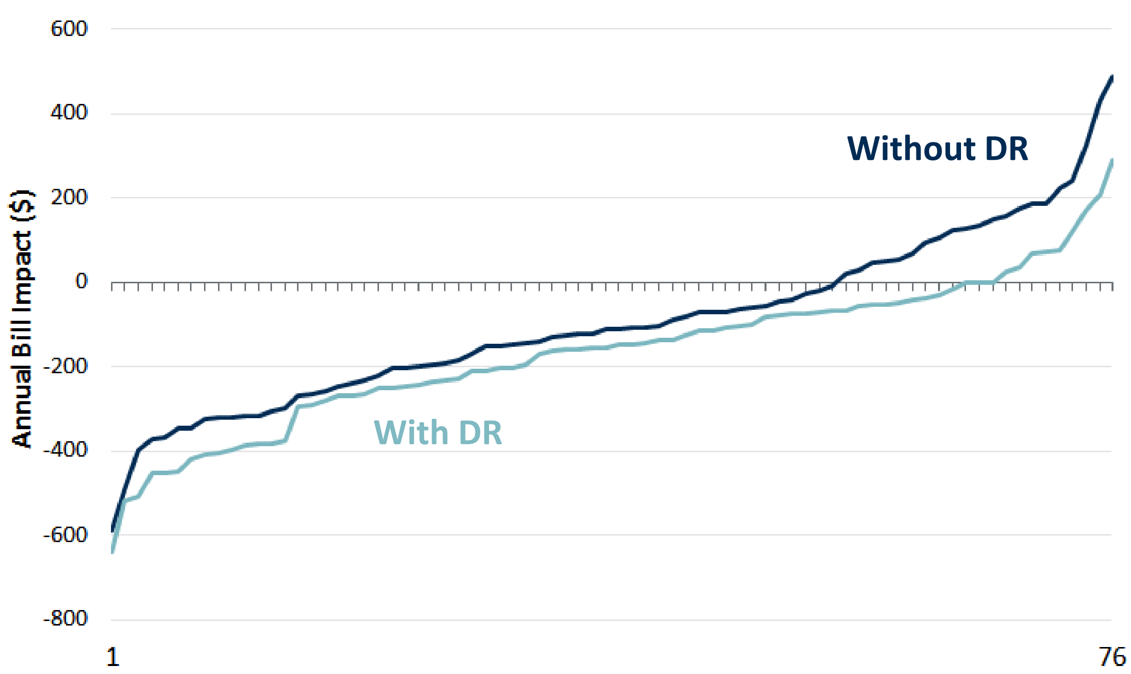
- Without DR, there is an average bill reduction of $167 and an average bill increase of $159, with an overall average bill impact of **$4**
- With DR, there is an average bill reduction of $205 and a single bill increase of $104, with an overall average bill impact of **-$132**



Residential Bill Impacts
TOU/CPP #4B, without Electric Heat

Under the TOU/CPP #4B rate, 72% of non-electric heat customers experience *lower bills* without demand response compared to 88% with demand response

- Without DR, there is an average bill reduction of $194 and an average bill increase of $162, with an overall average bill impact of **-$96**
- With DR, there is an average bill reduction of $206 and a single bill increase of $118, with an overall average bill impact of **-$167**



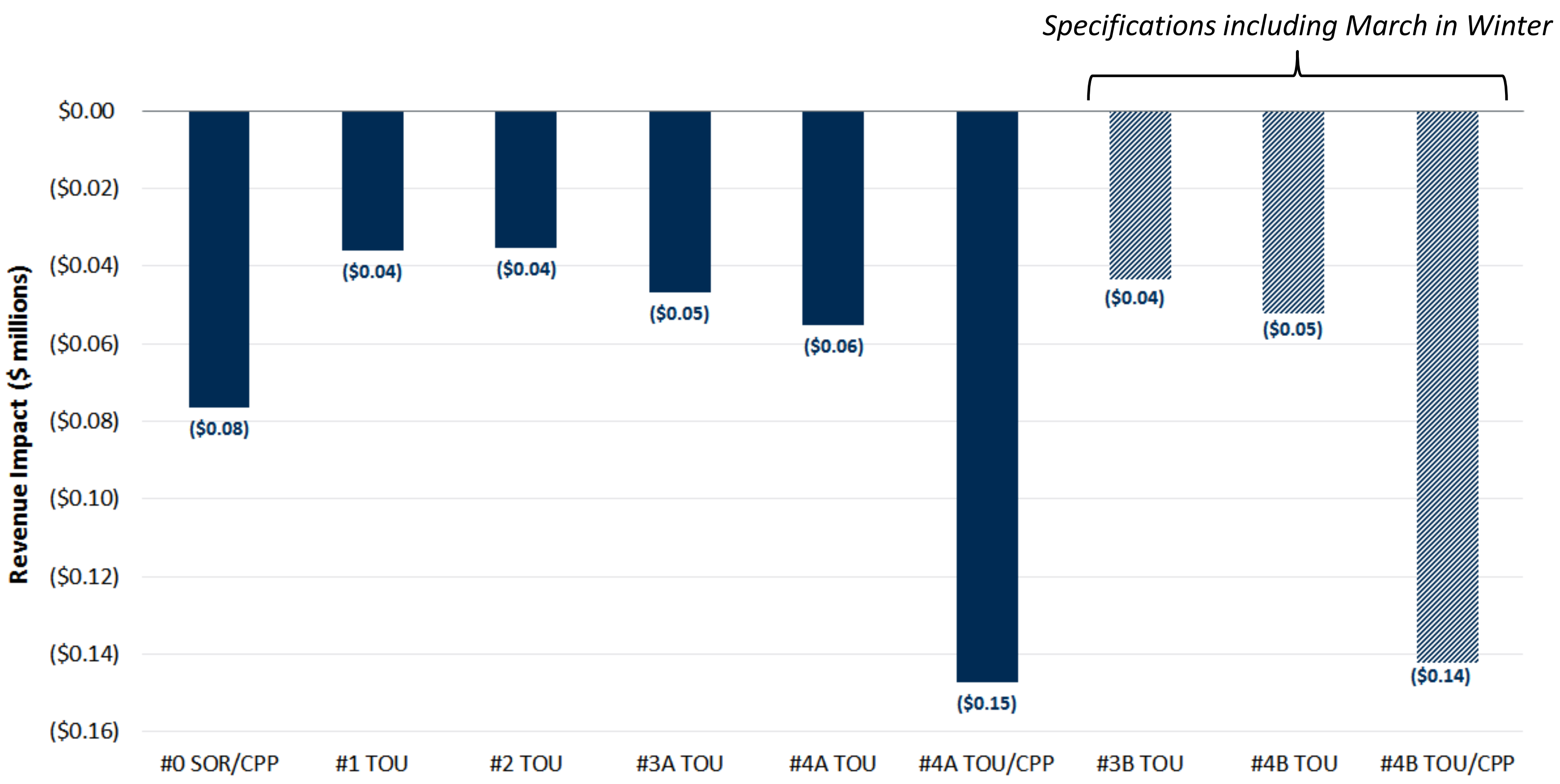
Residential Class Scorecard of TVP Options

	Rate Simplicity	Per-Participant Peak Load Impact (%)	Aggregate Peak Impact (MW)	Revenue Impact ($M)	% whose bills instantly decrease	% whose bills decrease with DR
TOU1	Low	4.4%	7.4	1.6	69%	83%
TOU2	Low	4.4%	7.4	1.7	70%	83%
TOU3A	Medium	5.1%	8.6	1.9	64%	74%
TOU3B	Medium	4.7%	7.9	1.7	60%	72%
TOU4A	High	5.7%	9.6	2.2	69%	81%
TOU4B	High	5.3%	8.9	2.1	67%	84%
TOU4A/CPP	Low	5.9% *(TOU)* 13.6% *(CPP)*	22.8	5.4	62%	81%
TOU4B/CPP	Low	5.3% *(TOU)* 13.6% *(CPP)*	22.8	5.2	61%	83%
CPP	High	11.9% *(CPP)*	20	3.2	62%	76%

Notes: For TOU1 and TOU2, Peak Load Impact shown represent winter impacts. Aggregate Peak Load Impact is calculated assuming 15% participation. Peak Load and Revenue Impacts all represent decreases under the TVP offering. **% whose bills instantly decrease and % of whose bills decrease with DR represent the share of the 135 Residential customers in the load research sample (including 59 customers with electric heat and 76 without) who will experience lower bills under the TVP option relative to the Standard Offer Rate.**

SGS Class
Impact of TVP Rates on Revenue

Revenue impacts range from 0.1% (under the TOU1 and TOU2) to 0.4% (under the TOU/CPP4) assuming 15% customer participation



Small GS Bill Impacts
Methodology I

For nine of the proposed rate options, we prepared bill impact distributions for 80 Small General Service customers in NS Power's 2019 residential load research sample

- The analysis defines the **peak period** as hours ending 8-11 AM and 5-8 PM in winter, 8 AM-noon in Spring & Fall, and 1-7 PM in summer
  - The **CPP period** is defined as the top 88 load hours in the year according to NS Power's system load. Of these 88 hours, 40 occur in January, 47 in February, and 1 in March

Small GS Bill Impacts
Methodology II

Each customer's bill impact is computed using 2022 pricing options as:

Total annual bill under the new Time-Varying Rate *minus*

Total annual bill under the flat Standard Offer Rate

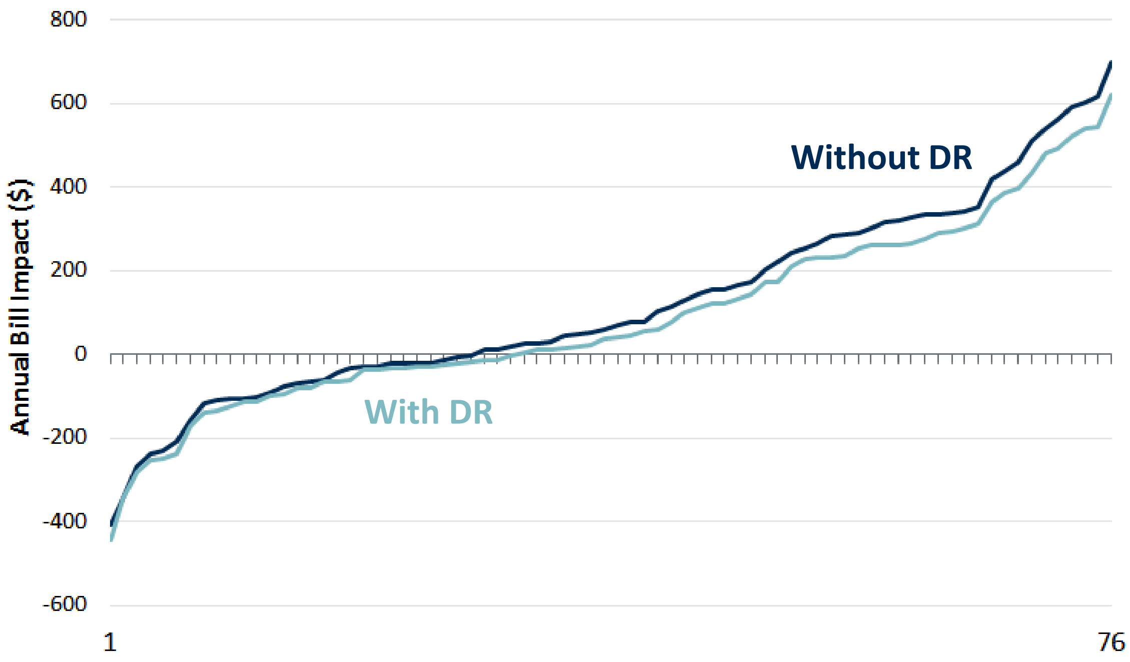
Bill impacts are computed both with and without demand response (DR) for each rate

- **Without DR,** bills are calculated assuming each customer's monthly peak and off-peak usage remain constant, with no load shifting between periods
- **With DR,** bills are calculated assuming customers shift usage from peak to off-peak hours (however no conservation is assumed)

Small GS Bill Impacts
CPP/SOR

Under the SOR/CPP rate, 35% of customers experience *lower bills* without demand response compared to 39% with demand response

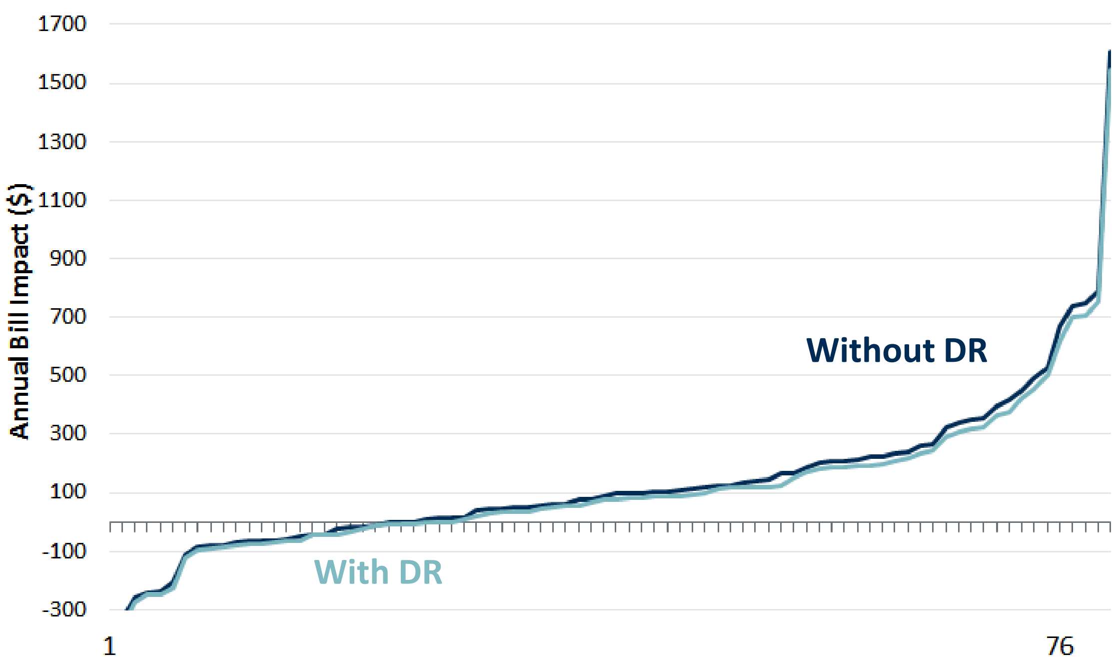
- Without DR, there is an average annual bill reduction of $107 and an average annual bill increase of $300, with an overall average bill impact of **$157**
- With DR, there is an average bill reduction of $111 and an average bill increase of $272, with an overall average bill impact of **$123**



Small GS Bill Impacts
TOU #1

Under the TOU #1 rate, 29% of customers experience *lower bills* without demand response compared to 34% with demand response

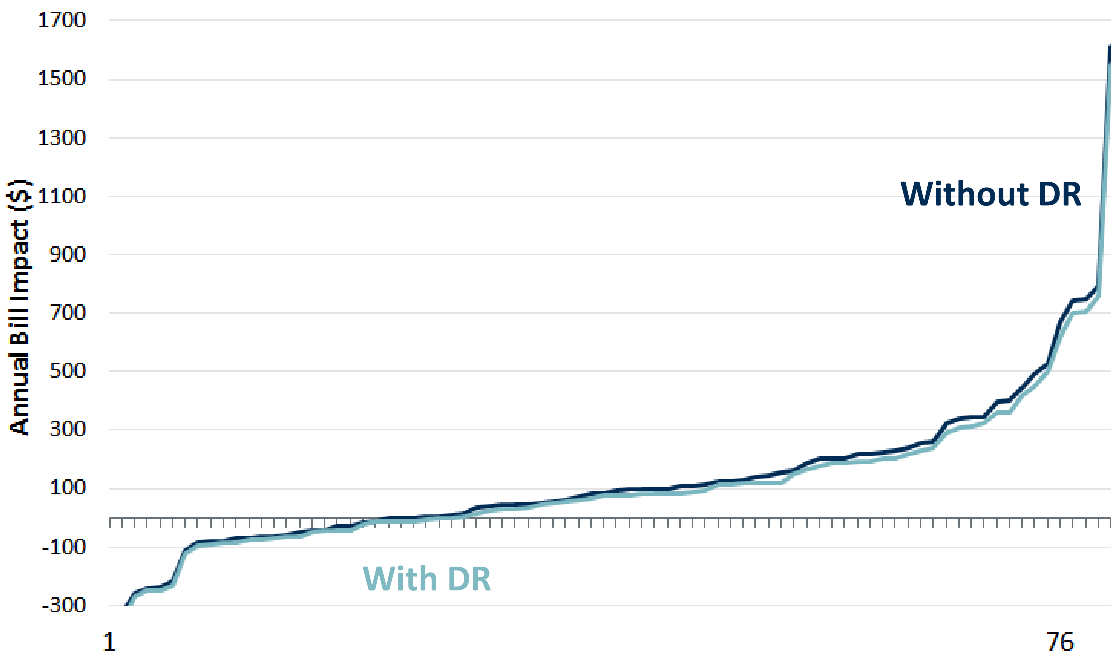
- Without DR, there is an average bill reduction of $110 and an average bill increase of $231, with an overall average bill impact of **$133**
- With DR, there is an average bill reduction of $103 and an average bill increase of $226, with an overall average bill impact of **$115**



Small GS Bill Impacts
TOU #2

Under the TOU #2 rate, 30% of customers experience *lower bills* without demand response compared to 34% with demand response

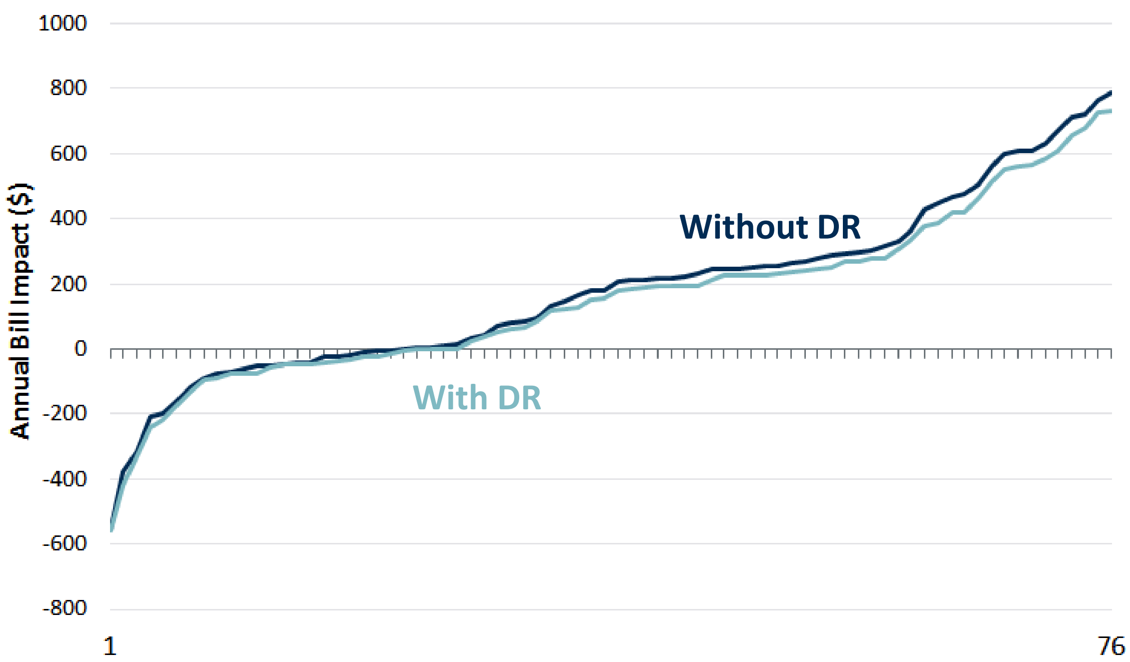
- Without DR, there is an average bill reduction of $107 and an average bill increase of $233, with an overall average bill impact of **$131**
- With DR, there is an average bill reduction of $105 and an average bill increase of $224, with an overall average bill impact of **$113**



Small GS Bill Impacts
TOU #3A

Under the TOU #3A rate, 28% of customers experience *lower bills* without demand response compared to 31% with demand response

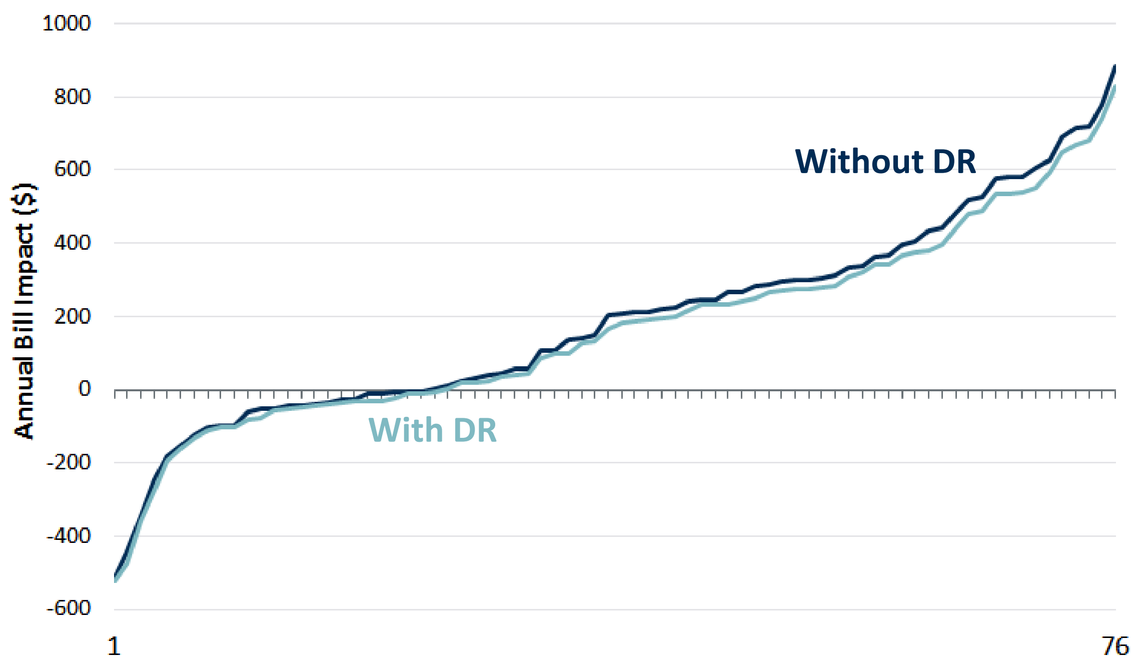
- Without DR, there is an average bill reduction of $116 and an average bill increase of $113, with an overall average bill impact of **$235**
- With DR, there is an average bill reduction of $114 and an average bill increase of $354, with an overall average bill impact of **$208**



Small GS Bill Impacts
TOU #3B

Under the TOU #3B rate, 30% of customers experience *lower bills* without demand response compared to 31% with demand response

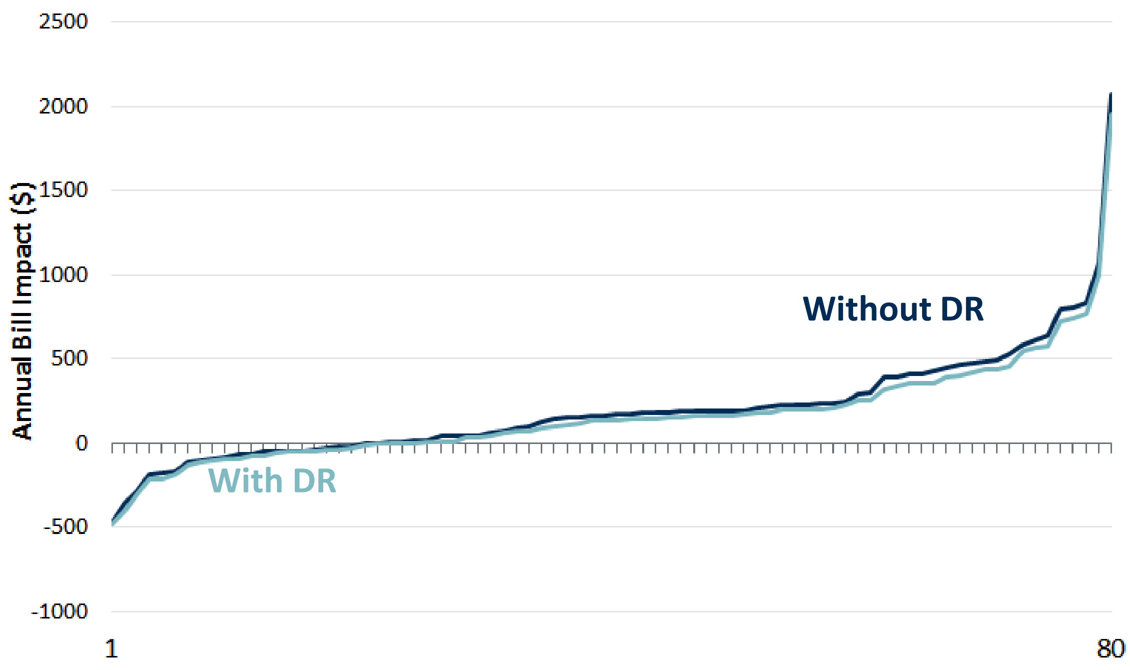
- Without DR, there is an average bill reduction of $114 and an average bill increase of $396, with an overall average bill impact of **$243**
- With DR, there is an average bill reduction of $121 and an average bill increase of $372, with an overall average bill impact of **$218**



Small GS Bill Impacts
TOU #4A

Under the TOU #4A rate, 28% of customers experience *lower bills* without demand response compared to 29% with demand response

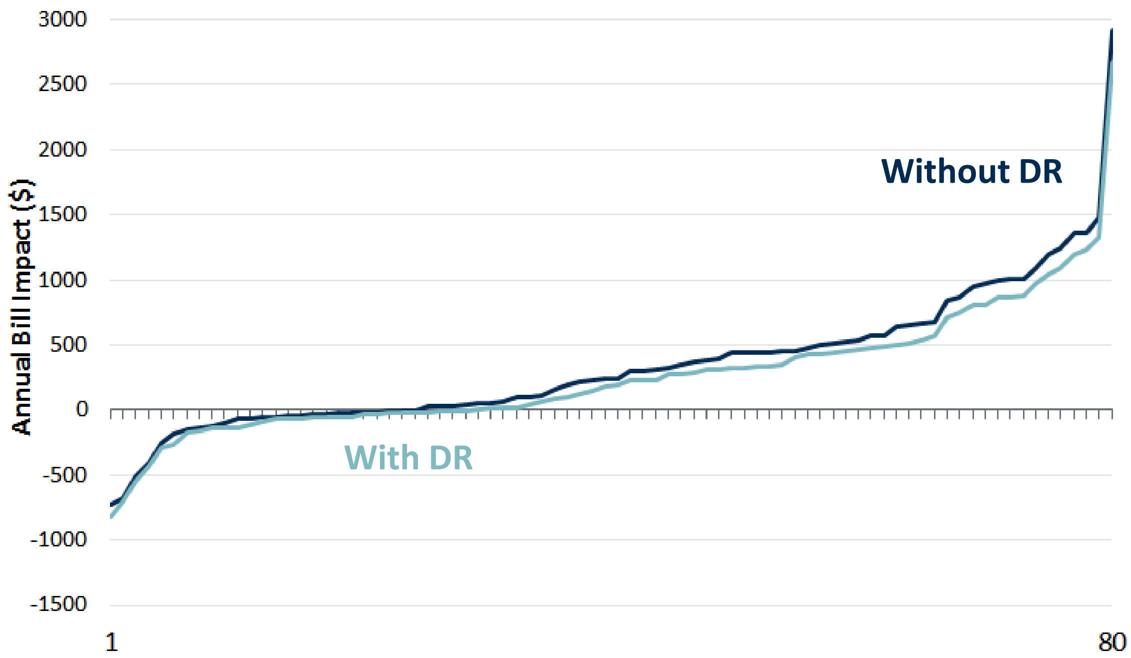
- Without DR, there is an average bill reduction of $113 and an average bill increase of $315, with an overall average bill impact of **$197**
- With DR, there is an average bill reduction of $122 and an average bill increase of $280, with an overall average bill impact of **$164**



Small GS Bill Impacts
TOU/CPP #4A

Under the TOU/CPP #4A rate, 31% of customers experience lower bills without demand response compared to 36% with demand response

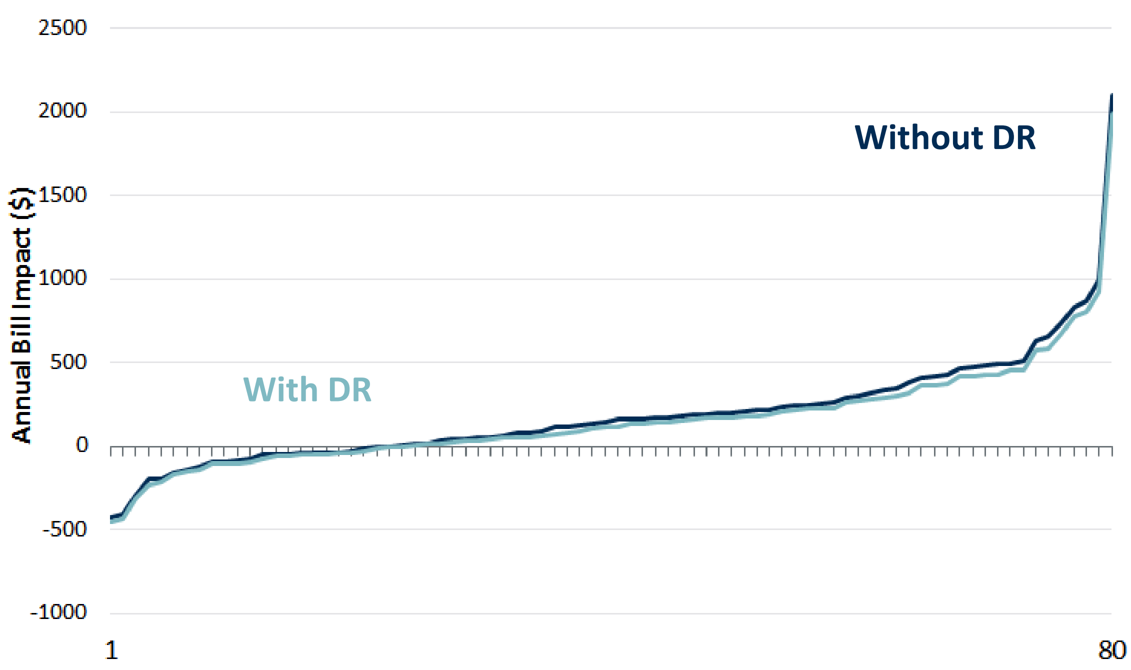
- Without DR, there is an average bill reduction of $151 and an average bill increase of $562, with an overall average bill impact of **$339**
- With DR, there is an average bill reduction of $158 and a single bill increase of $504, with an overall average bill impact of **$264**



Small GS Bill Impacts
TOU #4B

Under the TOU #4B rate, 29% of customers experience *lower bills* without demand response compared to 30% with demand response

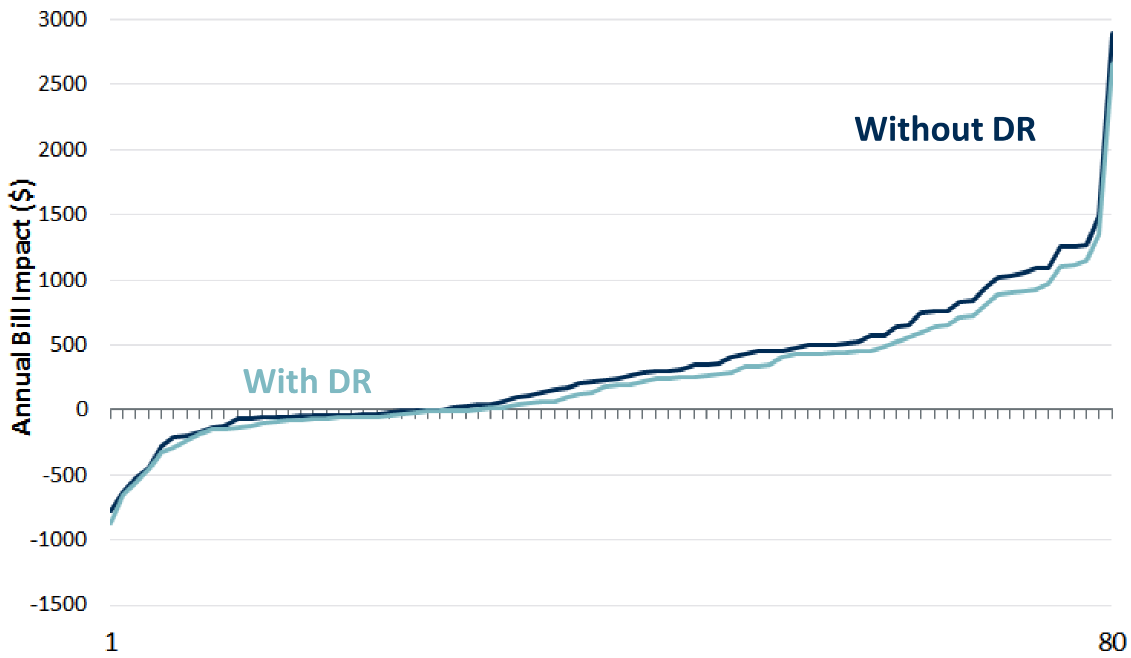
- Without DR, there is an average bill reduction of $116 and an average bill increase of $312, with an overall average bill impact of **$189**
- With DR, there is an average bill reduction of $125 and an average bill increase of $280, with an overall average bill impact of **$159**



Small GS Bill Impacts
TOU/CPP #4B

Under the TOU/CPP #4B rate, 34% of customers experience lower bills without demand response compared to 36% with demand response

- Without DR, there is an average bill reduction of $152 and an average bill increase of $571, with an overall average bill impact of **$327**
- With DR, there is an average bill reduction of $170 and a single bill increase of $498, with an overall average bill impact of **$256**



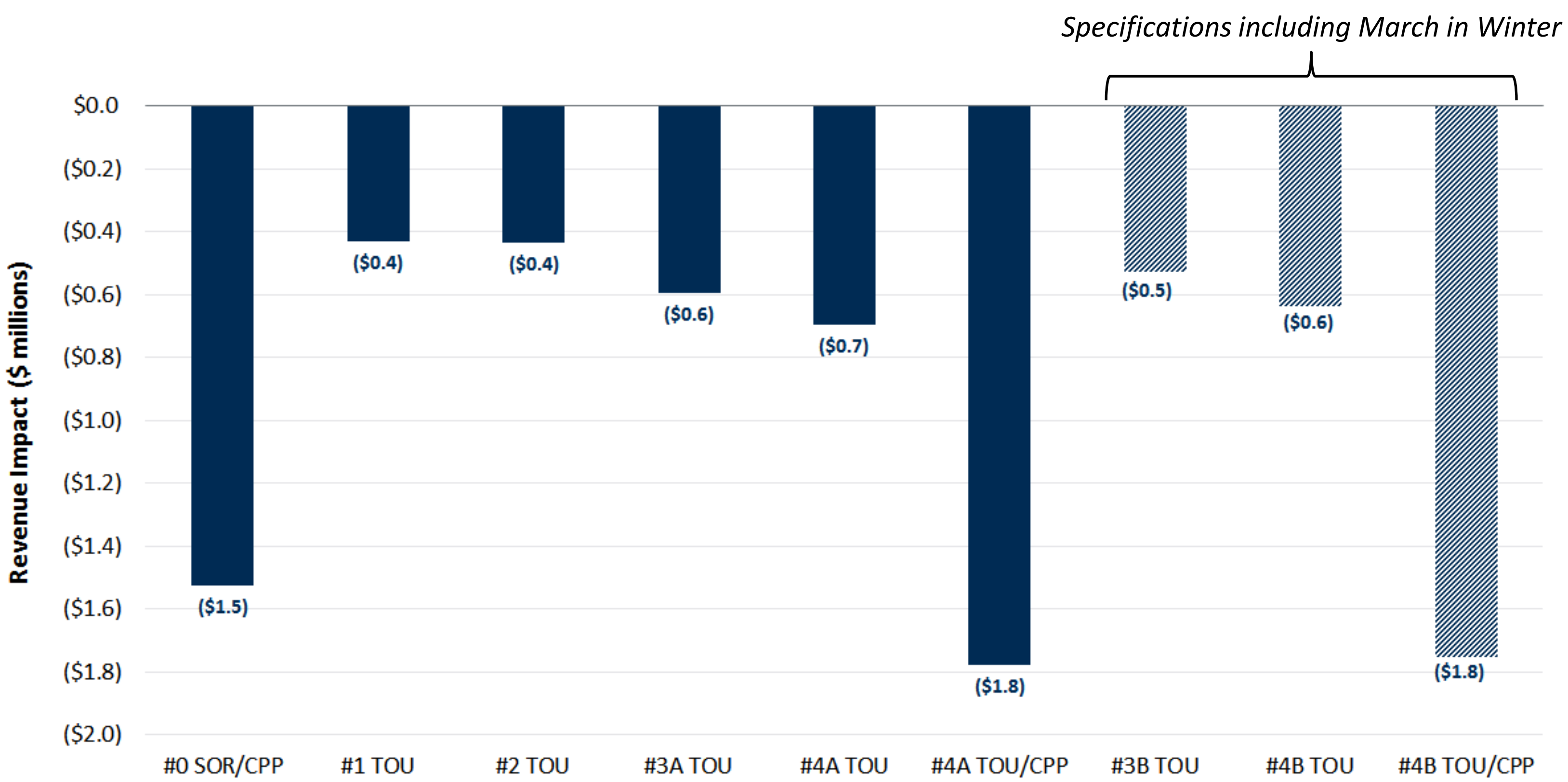
SGS Class Scorecard of TVP Options

	Rate Simplicity	Per-Participant Peak Load Impact (%)	Aggregate Peak Impact (MW)	Revenue Impact ($M)	% whose bills instantly decrease	% whose bills decrease with DR
TOU1	Low	1.9%	0.2	0.03	18%	19%
TOU2	Low	1.9%	0.2	0.03	18%	19%
TOU3A	Medium	2.6%	0.2	0.05	34%	35%
TOU3B	Medium	2.3%	0.2	0.04	33%	35%
TOU4A	High	2.8%	0.3	0.12	29%	35%
TOU4B	High	2.6%	0.2	0.05	30%	31%
TOU4A/CPP	Low	3.2% *(TOU)* 7.0% *(CPP)*	0.6	0.14	44%	53%
TOU4B/CPP	Low	2.9% *(TOU)* 7.0% *(CPP)*	0.6	0.14	43%	54%
CPP	High	6.2% *(CPP)*	0.6	0.08	35%	39%

Notes: For TOU1 and TOU2, Peak Load Impact shown represent winter impacts. Aggregate Peak Load Impact is calculated assuming 15% participation.

GS Class
Impact of TVP Rates on Revenue

Revenue impacts range from 0.2% (under the TOU1 and TOU2) to 0.6% (under the TOU/CPP4) assuming 15% customer participation



GS Class Scorecard of TVP Options

	Rate Simplicity	Per-Participant Peak Load Impact (%)	Aggregate Peak Impact (MW)	Revenue Impact ($M)
TOU1	Low	3.4%	2.4	0.4
TOU2	Low	3.4%	2.4	0.4
TOU3A	Medium	4.6%	3.2	0.6
TOU3B	Medium	4.1%	3.6	0.5
TOU4A	High	5.1%	9.3	0.7
TOU4B	High	4.6%	3.2	0.6
TOU4A/CPP	Low	3.6% *(TOU)* 13.1% *(CPP)*	9.3	1.8
TOU4B/CPP	Low	3.1% *(TOU)* 13.1% *(CPP)*	9.3	1.8
CPP	High	12.6% *(CPP)*	8.9	1.5

Notes: For TOU1 and TOU2, Peak Load Impact shown represent winter impacts. Aggregate Peak Load Impact is calculated assuming 15% participation.

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THE Brattle GROUP

A Blueprint to Pilot Design: Best Practices and Lessons Learned

PRESENTED TO

NS Power

PRESENTED BY

Ahmad Faruqui, Ph.D.
Sanem Sergici, Ph.D.

June 2020

THE Brattle GROUP

Introduction

Many utilities and jurisdictions have been testing innovative rate designs and/or technologies over the past two decades

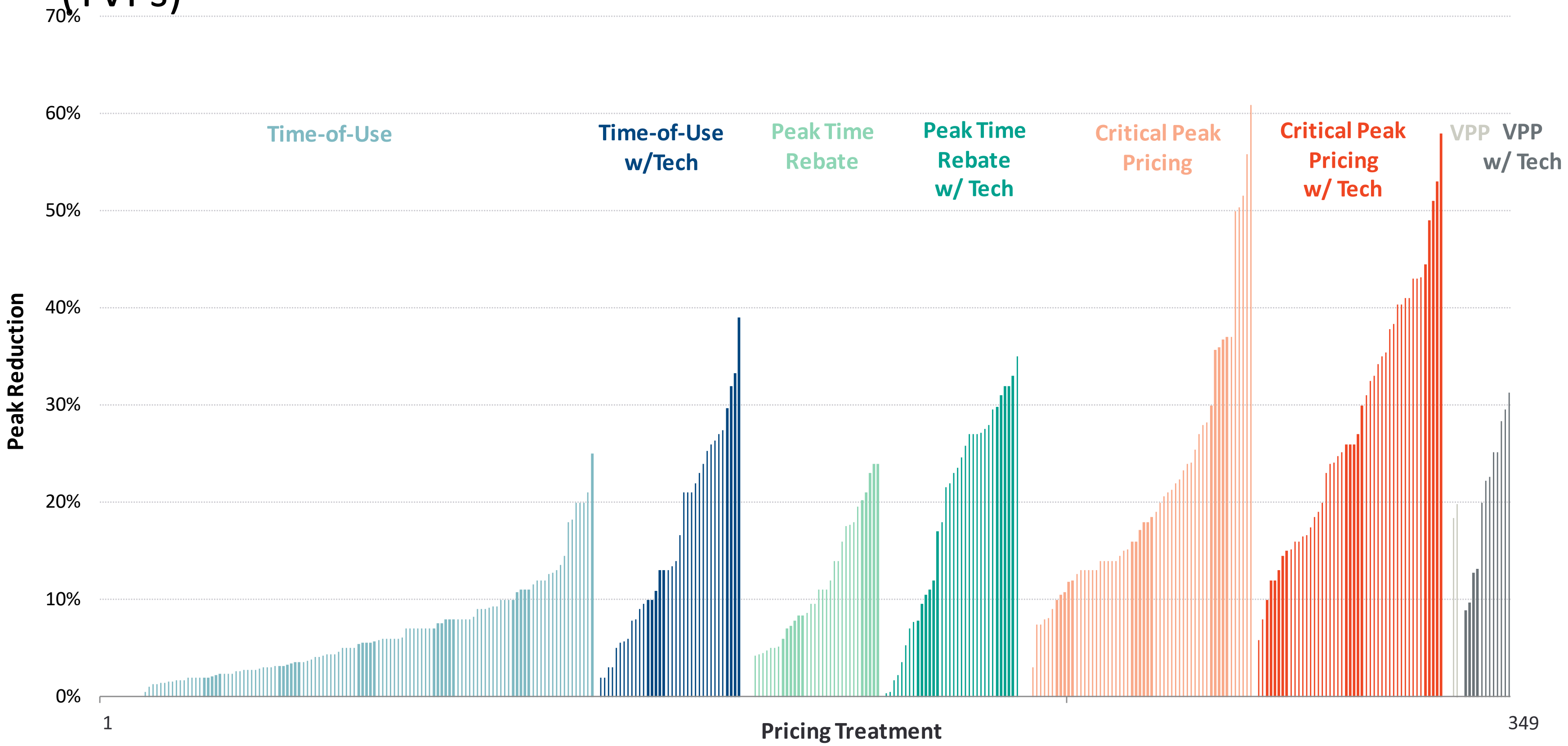
- These innovative/alternative rate designs address one or more deficiencies of the current flat and volumetric rate construct
- Customer response and experience with these rates should be understood before offering these rates to the broader population

Brattle has been maintaining a database of the pricing and technology pilots conducted in the U.S. to track customer responsiveness to these rates, as well as to improve the state of the art for the next generation of pilots

It is important to that pilots are a form of "limited deployment" with clear plans of measurement, verification and evaluation

Customer response to time varying prices is well understood

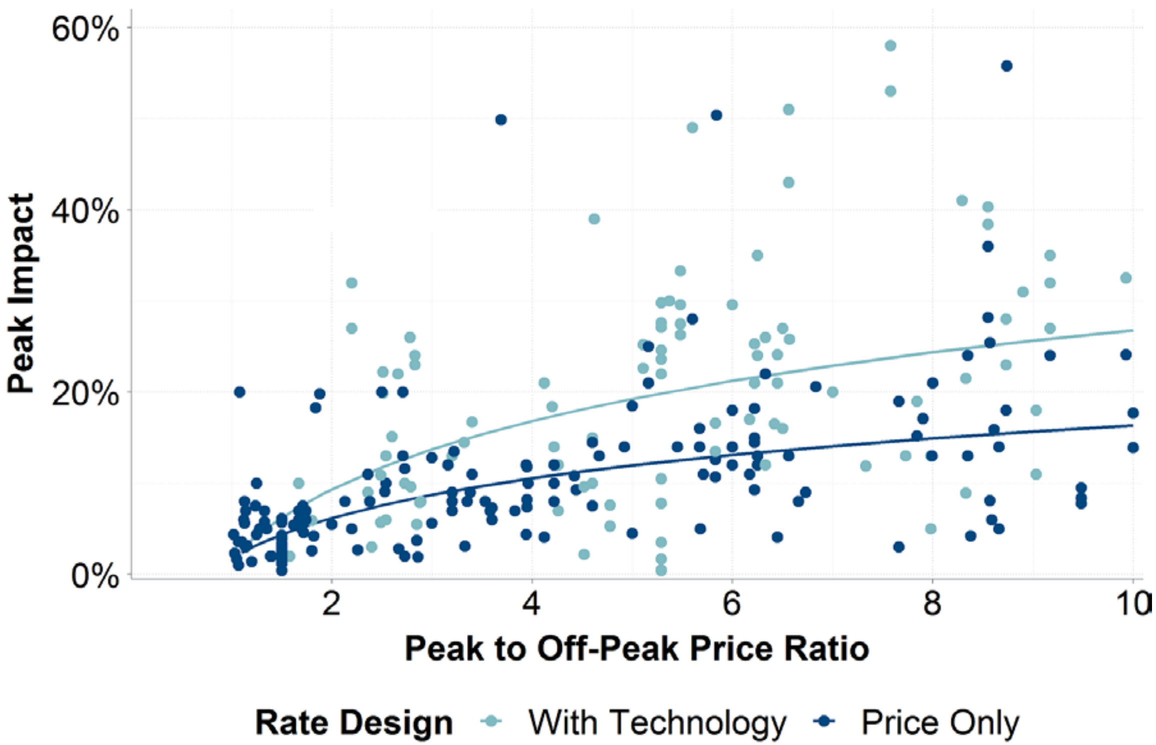
Based on the experimentation over the past decade, we have conclusive evidence that customers respond to time varying prices (TVPs)



Source: Results from 349 pricing experiments in Arcturus database.

Brattle developed tools to estimate the impact of TVPs using data from previous pilots

We have built a model called **"PRISM"** to estimate the impacts using price elasticities and also developed an **impact curve** that approximate the peak impact as a function of peak/off-peak ratio



Given the existing evidence on customer responsiveness, do we need more pilots?

There are high level takeaways one can glean from other pilots, however it is rarely the case that the deployment and design scenarios are identical across different jurisdictions, For instance:

- Opt-in vs. Opt-out
- RCT vs. randomly selected control group

In the event that you decide to do your own pilot, there are critical questions to answer:

- How would you articulate the objective of the pilot?
- What types of rates should you test in the pilot?
- What is the likely approach to offering these rates to the broader population (i.e. opt-in, opt-out, mandatory)?
- How should you design the experiment given the likely deployment approach?
- Should you also bundle some enabling technologies and information treatments along with the rates?
- Are you interested in measuring impact for sub-populations of interest (i.e. low income, NEM customers, etc.)

How should you proceed with the pilot?

1. Plan to run it **at least for a year** and plan on spending real money on it but no more than the value of information you hope to gain from the pilot
2. If the objective is to estimate customer behavior to dynamic pricing in addition to understanding customer acceptance, you will need to do an experiment that follows the **scientific principles of pilot design**
3. Prepare a **comprehensive pilot proposal** that should address the following:
   - Rate design details
   - Pilot design details (i.e. design approach, sample size calculations)
   - Marketing, customer education and recruitment plan
   - Evaluation, measurement and verification plan
   - Budget and cost recovery
   - Pilot timeline
4. Incorporate **stakeholder input** to the pilot proposal

Checklist for a Scientifically Valid Pilot Design

1. Clear articulation of pilot objectives
2. Internal validity, meaning a cause and effect relationship can be established between the treatment being tested (the TOU rate) in the pilot and the outcome of interest (change in peak usage)

   requires a robust control group and pre-treatment data
3. External validity, meaning that the results from the pilot program can be extrapolated to the population of interest

   requires pilot recruitment to mimic potential wide scale deployment; can be ensured by selecting appropriate design approach
4. Determine sampling frame/eligible population for the pilot
5. Undertake "statistical power calculations" to determine minimum size requirement for treatment and control groups to detect statistically significant impacts
6. Incorporate attrition assumptions in the final sample sizes

Scientifically Valid Pilot Design Approaches (and control group strategy)

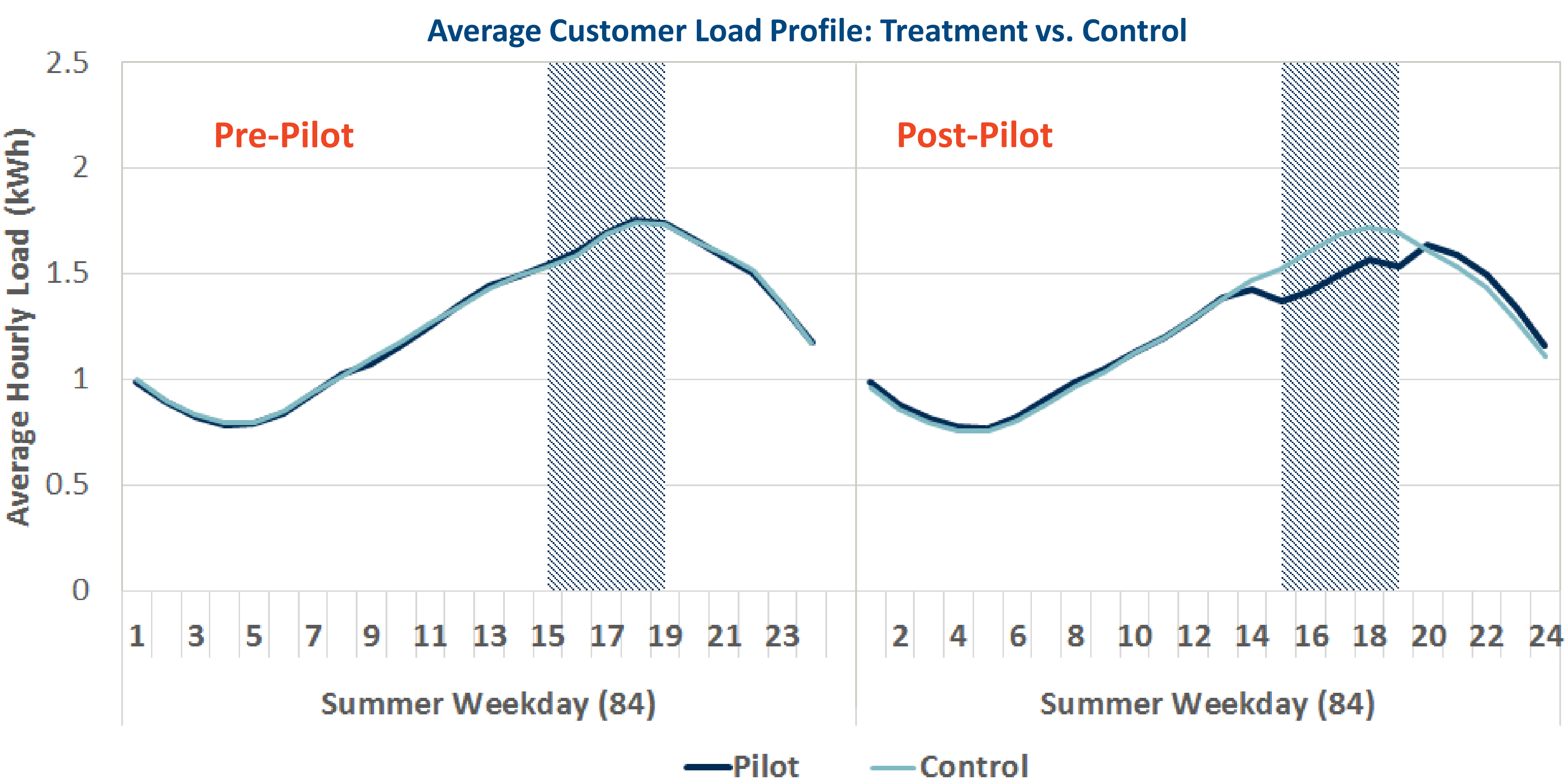
There are three widely accepted pilot design approaches

Possible Pilot Design Approaches	Description and Pros/Cons
Randomized Controlled Trial ("RCT")	Involves a random assignment of the recruited customers into the treatment and control groups. While this is the most rigorous approach from a measurement perspective, it is rarely used by electric utilities due to a potentially adverse impact on customer satisfaction (as it would involve either "recruit-and-deny" or "recruit-and-delay" approaches for some portion of the recruited customers).
Randomized Encouragement Design ("RED")	Allows the researcher to construct a valid control group, maintaining the benefits of an RCT design by not negatively affecting the customer experience. However, it requires much larger sample sizes, relative to the RCT approach, in order to be able to detect a statistically significant impact. Large sample sizes increase pilot implementation costs.
Random Sampling with Matched Control Group	Involves recruiting treated customers from a randomly selected sample, and using regression analysis to identify and match customers from the rest of the population that are most similar to the treatment customers. This matched control group approach strikes a good balance between achieving statistically valid results and requiring a manageable level of pilot participants.

Source: Sergici *et al.*, *"Evaluation, Measurement and Verification Plan for the PC44 TOU Pilots," prepared for PC44 Rate Design Work Group, June 2018.*

A statistically valid pilot design yields comparable treatment and control groups

This is an essential requirement in order to be able to attribute the difference between the two groups to the treatment impact



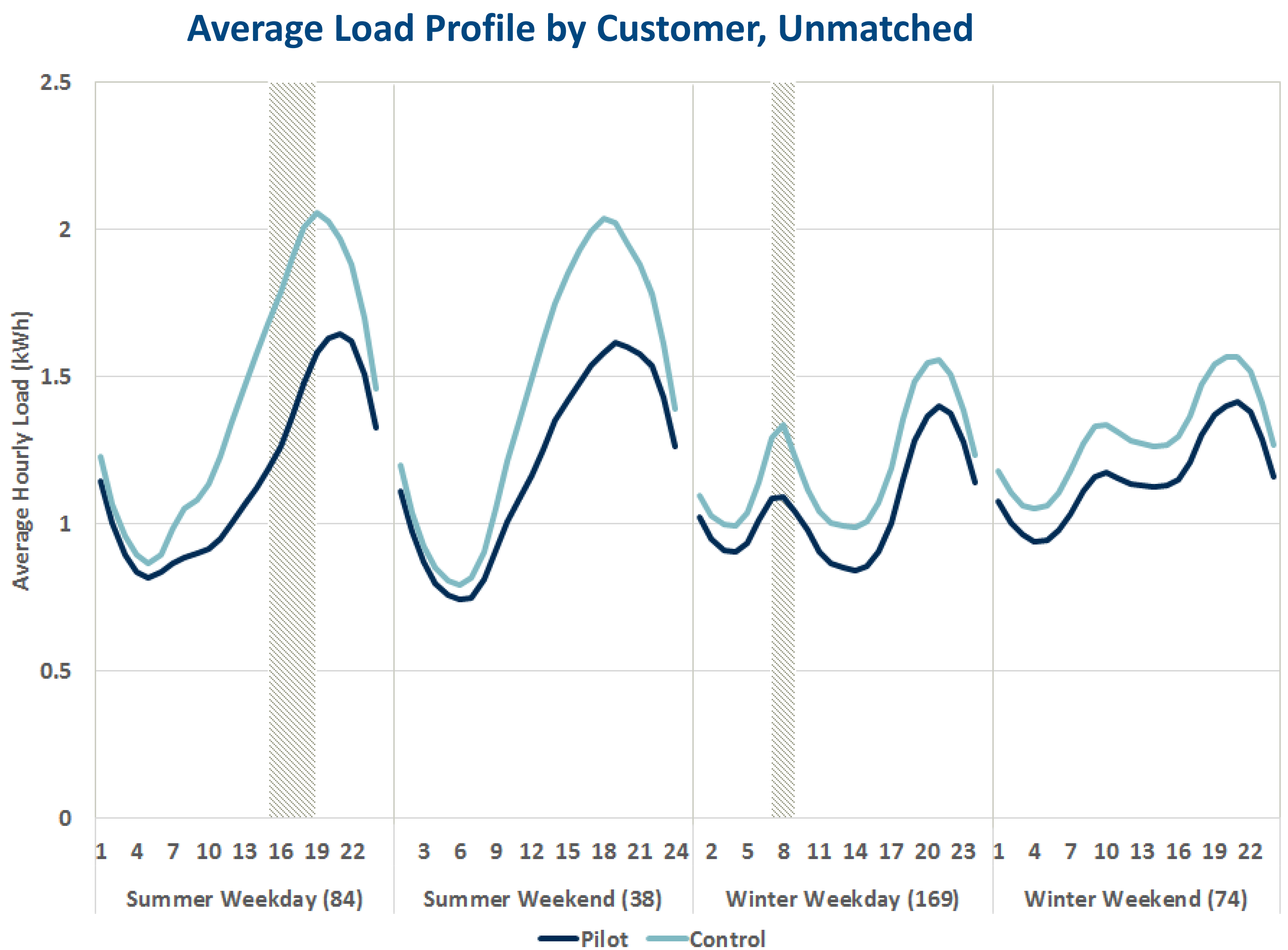
Note: The shaded regions indicate peak hours. Control group was constructed using a matching analysis

While RCT and RED are the most rigorous design options, implementation considerations may call for matched control groups

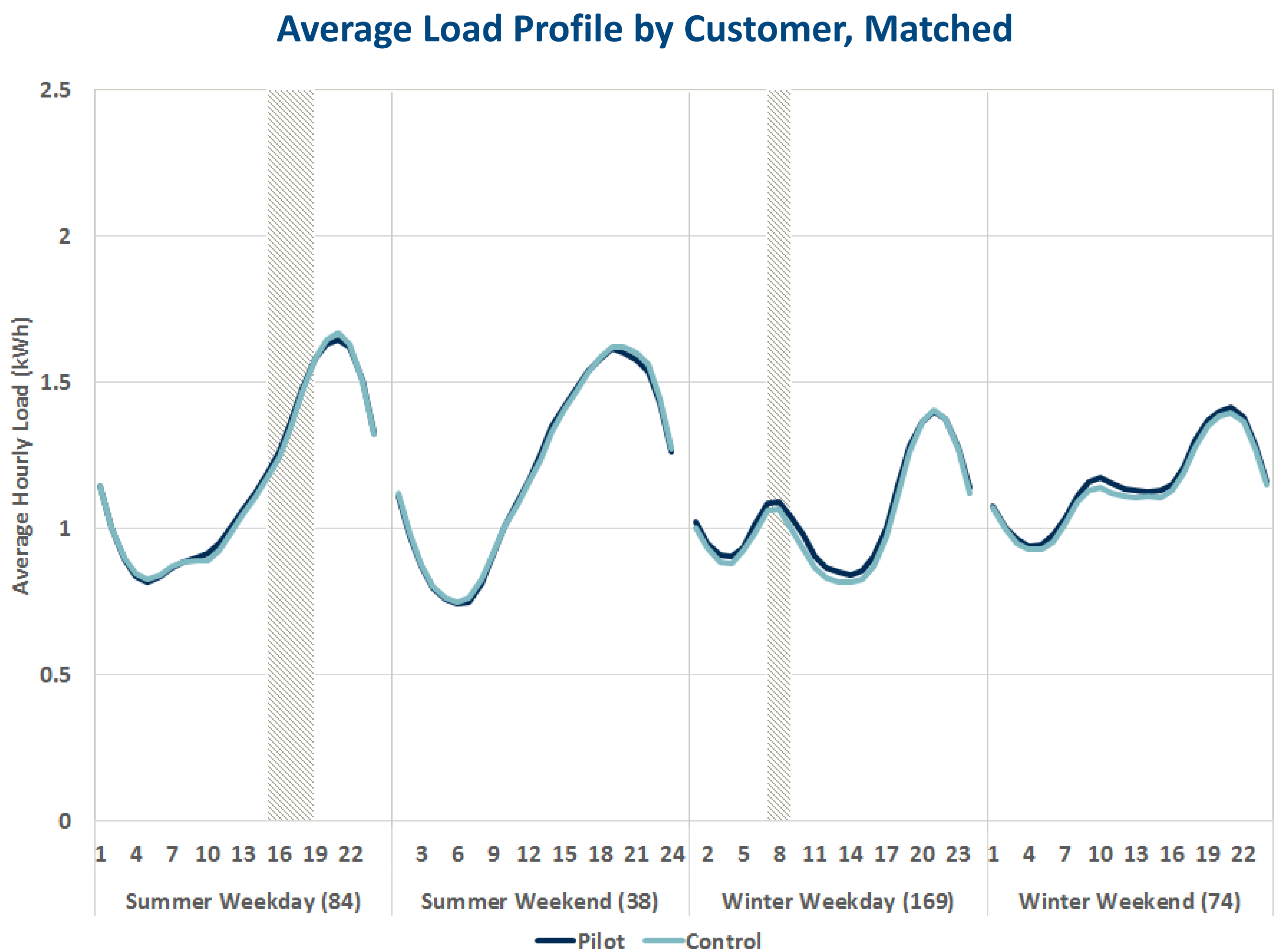
Propensity score matching is a widely-used statistical matching method in economics and other social sciences

- Uses statistical analysis to identify the variables that are most closely correlated with enrollment in the pilot
- Using the results of that analysis, "predicts" the probability of participation for both enrollees and control group
- Identifies, for each enrollee, a control group member who is "most similar" with respect to the observed covariates
- The ultimate goal is "covariate balance" – we want the control group averages to be as close as possible to the pilot group averages, particularly on the variables that "matter" the most
- Achieving "perfect" balance is rare, but this approach is usually successful, on net, in generating a control group that "looks like" the "treatment" group

Treatment vs. Control groups (Before Matching)



Treatment vs. Control groups (After Matching)

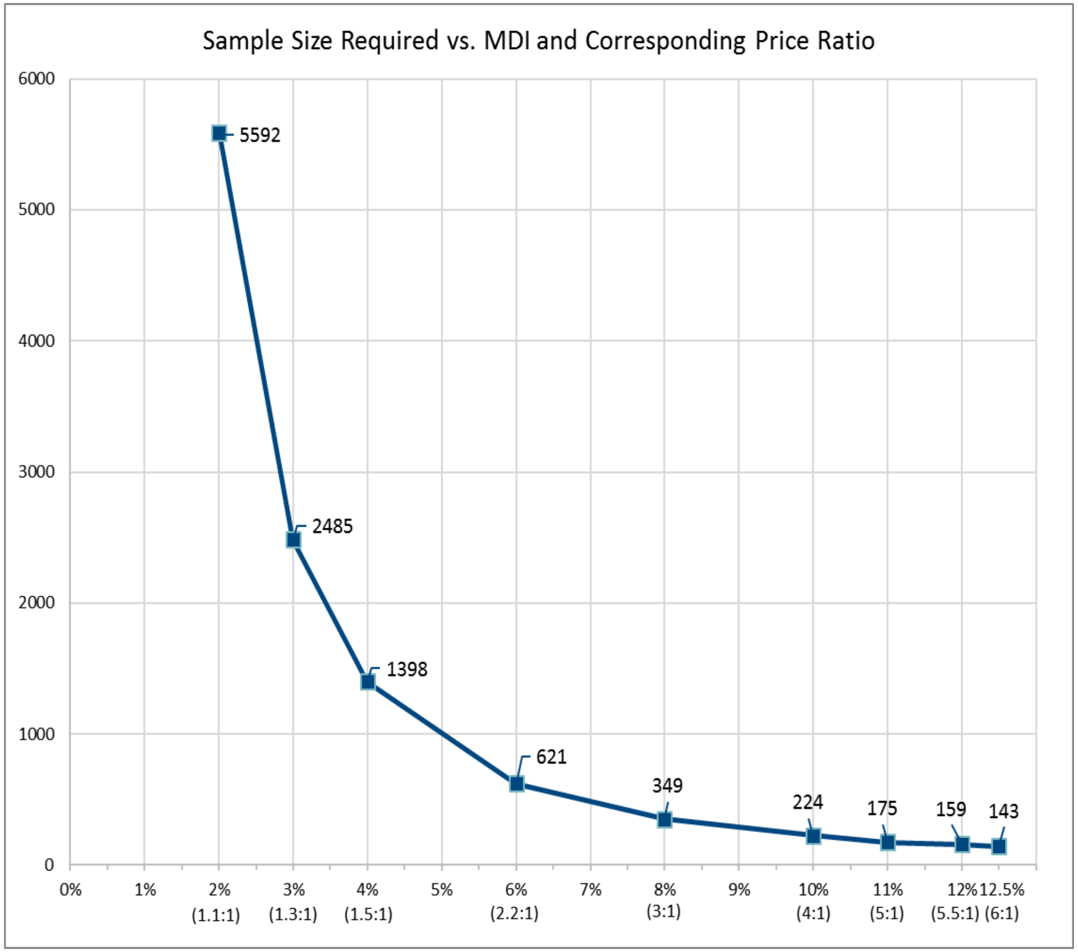


How big of a sample size needed?

In order to determine the pilot's impact in a statistically significant fashion, the sample size should be large enough. There are several parameters that affect the sample size

Parameter	Description of parameter
Group means	Average amount of electricity consumed by each group
Standard deviations	Amount that electricity consumption varies across households within each group
Number of repeat observations	Number of observations per household
Correlation coefficients	Degree to which electricity consumption is similar over time for a given household in the treatment and/or control group(s)
Statistical significance	Degree of certainty that the program reduces usage [one-sided test]
Statistical power	Degree of certainty that the statistical test gives the correct answer

Statistical power calculations are necessary to determine the sample size



Statistical power calculations are necessary to ensure sample size is large enough to detect statistically significant impacts

- As the minimum detectable impact (MDI) increases (i.e. due to higher peak to offpeak ratio), sample size requirement decreases
- As the statistical power and statistical significance requirements increase, the sample size increases
- As the resolution of the analysis increases (i.e. hourly vs. monthly), sample size requirement decreases

Pilot Design Approaches Used in Other Pilots

Early pilots typically relied on *random sampling with voluntary participation + randomly selected control groups*

- California Statewide Pricing Pilot, 2003; Baltimore Gas and Electric Smart Energy Pricing Pilot, 2007)

Some of the more recent pilots used *RCT and RED*

- SMUD SmartPricing Pilot, 2014; Ontario RPP Pilots, 2018

However, practical considerations (i.e., denying participation to the recruited customers in the RCT or large sample size requirements of RED) were not surmountable for other recent pilots. These pilots opted to use *random sampling with matched control group*

- PC44 TOU Pilot in Maryland, 2019; PowerPath DC Pepco Residential TOU Pilot, 2020; Alectra Advantage Power Pricing Pilot, 2017.

Checklist for the Recruitment Process

Practices followed in the recruitment process play a key role in maintaining the validity of the pilot design and offer important insights for broader deployments

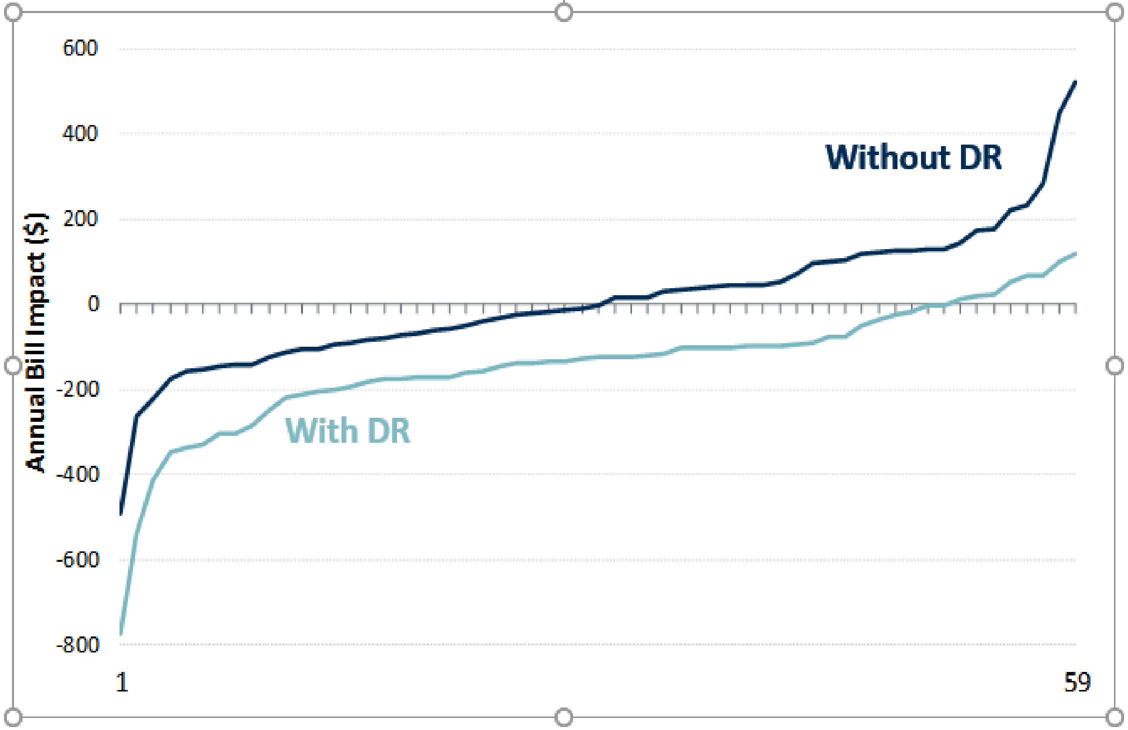
- Follow best practices in developing customer education and outreach materials (including samples of effective vs. ineffective marketing materials)
- Consider different recruitment strategies through different channels based on the type of treatment offered and recruitment for special interest groups
- Identify approaches to minimize marketing costs while maximizing the number of recruited customers;
- Develop strategies to improve retention rates
- Be aware of correct and incorrect ways to introduce incentives to the recruitment process
- Incorporate new information that becomes available during the recruitment process to improve the success of recruitment
- Provide robust training to the marketing team to ensure that they don’t inadvertently compromise
- Design pre- and post-treatment customer experience surveys aligned with pilot objectives

Common Mistakes during Recruitment

- Recruitment team deviating from the pilot design plan to meet the sample size targets
- Nonexistent or infrequent communication between the recruitment and design teams that might introduce inefficiencies to the overall pilot management
  - Loss of marketing cost savings
  - Loss of valuable course correction opportunities
- Misuse of incentive payments
- Recruitment starting around the holiday times
- Recruitment process that necessitates too many touch points with the customers before sign up
- Not capturing useful customer interactions/communications that might inform future program deployment strategies

Bill impact analyses are useful to understand the distributional impacts of the new rates

Annual Bill Impact Distribution with TOU Rates



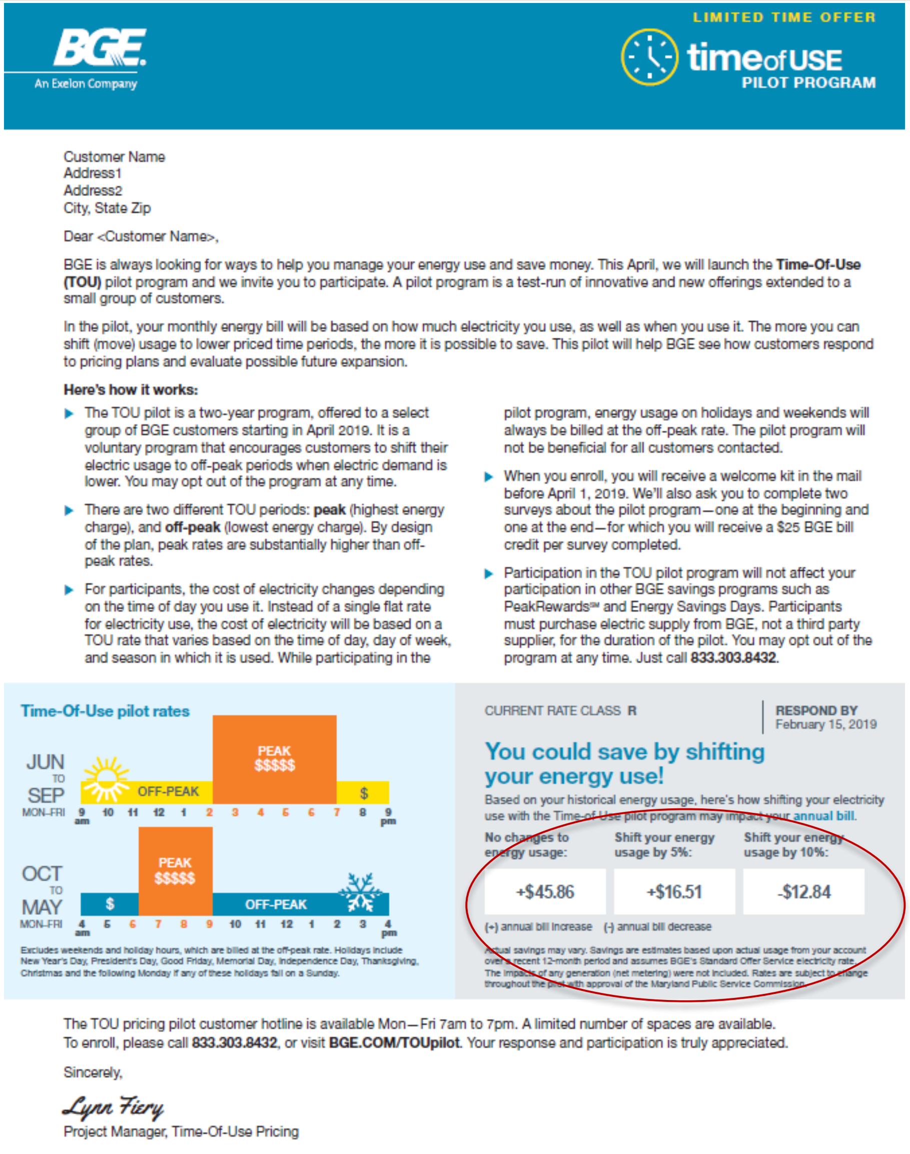
Under this rate, 51% of customers experience *lower bills* without DR compared to 86% with demand response

It is useful to undertake a bill impact analysis of the eligible customer population under the new rates

The bills would be calculated twice: before load response and after load response

Some utilities/jurisdictions choose to include this information for individual customers in the recruitment materials

Bill Impact Analysis Presentment to the Customers



BGE
An Exelon Company

LIMITED TIME OFFER
time of USE
PILOT PROGRAM

Customer Name
Address1
Address2
City, State Zip

Dear <Customer Name>,

BGE is always looking for ways to help you manage your energy use and save money. This April, we will launch the **Time-Of-Use (TOU)** pilot program and we invite you to participate. A pilot program is a test-run of innovative and new offerings extended to a small group of customers.

In the pilot, your monthly energy bill will be based on how much electricity you use, as well as when you use it. The more you can shift (move) usage to lower priced time periods, the more it is possible to save. This pilot will help BGE see how customers respond to pricing plans and evaluate possible future expansion.

Here's how it works:

- The TOU pilot is a two-year program, offered to a select group of BGE customers starting in April 2019. It is a voluntary program that encourages customers to shift their electric usage to off-peak periods when electric demand is lower. You may opt out of the program at any time.
- There are two different TOU periods: **peak** (highest energy charge), and **off-peak** (lowest energy charge). By design of the plan, peak rates are substantially higher than off-peak rates.
- For participants, the cost of electricity changes depending on the time of day you use it. Instead of a single flat rate for electricity use, the cost of electricity will be based on a TOU rate that varies based on the time of day, day of week, and season in which it is used. While participating in the pilot program, energy usage on holidays and weekends will always be billed at the off-peak rate. The pilot program will not be beneficial for all customers contacted.
- When you enroll, you will receive a welcome kit in the mail before April 1, 2019. We'll also ask you to complete two surveys about the pilot program—one at the beginning and one at the end—for which you will receive a $25 BGE bill credit per survey completed.
- Participation in the TOU pilot program will not affect your participation in other BGE savings programs such as PeakRewards℠ and Energy Savings Days. Participants must purchase electric supply from BGE, not a third party supplier, for the duration of the pilot. You may opt out of the program at any time. Just call **833.303.8432**.

Time-Of-Use pilot rates

JUN TO SEP MON-FRI: OFF-PEAK 9 am – 2; PEAK $$$$$ 2 – 7; $ 7 – 9 pm

OCT TO MAY MON-FRI: $ 4 am – 6; PEAK $$$$$ 6 – 9; OFF-PEAK 9 – 4 pm

Excludes weekends and holiday hours, which are billed at the off-peak rate. Holidays include New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Thanksgiving, Christmas and the following Monday if any of these holidays fall on a Sunday.

CURRENT RATE CLASS **R**

RESPOND BY
February 15, 2019

You could save by shifting your energy use!

Based on your historical energy usage, here's how shifting your electricity use with the Time-of-Use pilot program may impact your annual bill.

No changes to energy usage:	Shift your energy usage by 5%:	Shift your energy usage by 10%:
+$45.86	+$16.51	-$12.84

(+) annual bill increase (-) annual bill decrease

Actual savings may vary. Savings are estimates based upon actual usage from your account over a recent 12-month period and assumes BGE's Standard Offer Service electricity rate. The impacts of any generation (net metering) were not included. Rates are subject to change throughout the pilot with approval of the Maryland Public Service Commission.

The TOU pricing pilot customer hotline is available Mon—Fri 7am to 7pm. A limited number of spaces are available. To enroll, please call **833.303.8432**, or visit **BGE.COM/TOUpilot**. Your response and participation is truly appreciated.

Sincerely,

Lynn Fiery
Project Manager, Time-Of-Use Pricing

Participants of the TOU pilot program are subject to the Terms & Conditions which are available online at **BGE.COM/TOUpilot** or by calling the customer hotline at **833.303.8432**.

PC44 pilot currently underway in Maryland included each customer's bill impact analysis in the recruitment letter

Customers were informed of the bill impact if:

- They did not change their usage
- Shift their peak usage by 5%
- Shift their peak usage by 10%

Since the Joint Utilities decided that they would present this information in a full scale rollout, this implementation did not compromise external validity

Checklist for the Impact Evaluation

The experimental design of each pilot dictates the optimal evaluation method: differences-in-differences (ANOVA or ANCOVA); panel regressions (fixed-effects or random-effects); individual customer regressions

- Decide on the **evaluation approach** based on the experimental design
- Identify **load impact metrics** to be quantified (i.e. peak, mid-peak, off-peak impacts, average daily conservation impact, etc.)
- Estimate alternative models and select the one that leads to most accurate predictions
- Decide whether quantifying customers' overall price responsiveness would be useful in the form of **price elasticities**, beyond the ex-post load impacts quantified in the pilot
    - Own/daily price elasticity (captures the change in the level of overall consumption due to the changes in the average daily price
    - Substitution price elasticity (captures customer's ability to substitute inexpensive off-peak consumption for more expensive peak consumption)

Is price elasticity estimation necessary?

Most pilot studies test a single price level for a given rate design

- As a result, impact evaluation quantifies the impact associated with that particular rate

If the Company is likely to offer other rate designs, or different price levels for the same rate design, it is very useful to estimate the own price and substitution price elasticities

Estimating elasticities using the pilot data **allow computation of the load impacts from other rate designs**, and have the benefit of reflecting utility's own customers' price responsiveness

Checklist for the Process Evaluation

A process evaluation consists of an assessment of the implementation of the program, with the goal of producing better and more cost-effective programs in the future

- Typically be conducted by surveying or soliciting feedback from the various groups involved in the pilot program, including both participants, implementers and administrators of the program

Data collection efforts include but are not limited to:

- Customer recruitment and outreach (pre-treatment survey)
- Customer acceptance and interest in treatment (post-treatment survey)
- Understanding the reasons for non-participation and attrition
- Quality control practices
- Time, schedule and budget management
- Lessons learned
- Project resource constraints and staff training
- In-field and back-office challenges with implementation

Recap I

Upfront investment in pilot planning is absolutely critical for the success of the pilot

- Well-developed EM&V plans, customer education and recruitment plans increase the likely success of the pilot

Seeking stakeholder input during the pilot design process and incorporating this input to the design increase the acceptability of the pilot results

Resist designing overly complex pilots that could easily interfere with meeting the essential objectives of the pilot

It is advisable to test treatments and functionality **only if they are likely to be offered in full scale deployments** (i.e., bill impacts, shadow bills, etc.)

Recap II

Avoid siloing the pilot design and marketing teams during the recruitment stage , as deviations from the recruitment plan may compromise the validity of the pilot

Estimation of price elasticities is desirable as part of an impact evaluation study to allow estimation of the impacts from alternative rates

It is important to **calculate sample sizes** consistent with the pilot design approach that will yield statistically significant results

An **interim impact evaluation** after the first season of the pilot is useful to gauge initial results and allow course-correction if needed

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Dr. Ahmad Faruqui has over 40 years of experience working on issues related to customer engagement, including rate design, load flexibility, distributed energy resources, demand forecasting, and electrification.

In his research and consulting career, Dr. Faruqui has worked for over 150 clients on five continents, and has published more than 100 papers on energy topics in peer-reviewed and trade journals. His work has been cited in *The Economist*, *Bloomberg Businessweek*, and *Forbes*, and he has appeared on NPR and Fox Business News. He has provided expert testimony, appeared before commissions, and presented to governments across the globe.

Dr. Faruqui has taught economics at three universities over a seven-year period and has delivered guest lectures at a dozen more universities, including MIT, Northwestern, Stanford, and UC Berkeley.

EDUCATION

- B.A. (highest honors) and M.A. (highest honors) in economics, mathematics, and statistics, University of Karachi
- M.A. in agricultural economics and Ph.D. in economics, The University of California at Davis

AREAS OF EXPERTISE

Expert witness

Dr. Faruqi has testified or appeared before state commissions in Arizona, Arkansas, California, Colorado, Connecticut, Delaware, the District of Columbia, FERC, Illinois, Indiana, Iowa, Kansas, Michigan, Maryland, Minnesota, Nevada, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, ECRA (Saudi Arabia), and Texas. He has been engaged by regulatory bodies in Alberta, New Brunswick, and has appeared as an expert witness before the Nova Scotia Utility and Review Board.

He has assisted clients in submitting testimony in Georgia and Minnesota.

He has made presentations to the California Energy Commission, the California Senate, the Congressional Office of Technology Assessment, the Kentucky Commission, the Minnesota Department of Commerce, the Minnesota Senate, the Missouri Public Service Commission, and the Electricity Pricing Collaborative in Washington state.

Innovative pricing

He has identified, designed and analyzed the efficiency and equity benefits of introducing innovative pricing designs such as three-part rates, including fixed monthly charges, demand charges and time-varying energy charges; dynamic pricing rates, including critical peak pricing, variable peak pricing and real-time pricing; time-of-use pricing; and inclining block rates.

Regulatory strategy

Dr. Faruqui has helped design forward-looking programs and services that exploit recent advances in rate design and digital technologies in order to lower customer bills and improve utility earnings, while lowering the carbon footprint and preserving system reliability.

- **Cost-benefit analysis of grid modernization**. He has assessed the feasibility of introducing smart meters and other devices, such as programmable communicating thermostats that promote demand response, into the energy marketplace, in addition to new appliances, buildings, and industrial processes that improve energy efficiency.
- **Demand forecasting and weather normalization**. He has pioneered the use of a variety of models for forecasting product demand in the near-, medium-, and long-term, using econometric, time series, and engineering methods. These models have been used to bid into energy procurement auctions, plan capacity additions, design customer-side programs, and weather normalize sales.
- **Customer choice**. He has developed methods for surveying customers in order to elicit their preferences for alternative energy products and alternative energy suppliers. These methods have been used to predict the market size of these products and to estimate the market share of specific suppliers.
- **Hedging, risk management, and market design**. He has helped design a range of financial products that help customers and utilities cope with the unique opportunities and challenges posed by a competitive market for electricity. He conducted a widely-cited market simulation to show that real-time pricing of electricity could have saved Californians millions of dollars during the Energy Crisis by lowering peak demands and prices in the wholesale market.
- **Competitive strategy**. He has helped clients develop and implement competitive marketing strategies by drawing on his knowledge of the energy needs of end-use customers, their values and decision-making practices, and their competitive options. He has helped companies reshape and transform their marketing organization and reposition themselves for a competitive marketplace. He has also helped government-owned entities in the developing world prepare for privatization by benchmarking their planning, retailing, and distribution processes against industry best practices, and suggesting improvements by specifying quantitative metrics and follow-up procedures.
- **Design and evaluation of marketing programs**. He has helped generate ideas for new products and services, identified successful design characteristics through customer surveys and focus groups, and test-marketed new concepts through pilots and experiments.

- **Academic experience**. He has given lectures at the University of California, Berkeley, University of California, Davis, Harvard University, University of Idaho, Massachusetts Institute of Technology, Michigan State University, Northwestern University, University of San Francisco, Stanford University, University of Virginia, and University of Wisconsin-Madison. Additionally, he has led a variety of professional seminars and workshops on public utility economics around the world. Finally, he has taught economics at San Jose State University, University of California, Davis, and the University of Karachi.

EXPERIENCE

Innovative Pricing

- **Cost of service and tariff design study.** For a large electric utility in South-East Asia, Brattle provided consulting services for their cost of service and tariff design studies for incentive-based regulation, covering regulatory period 2 (2018-2020). Our work focused on understanding the cost drivers, reviewing the extent to which the current tariffs reflect the cost drivers, and developing new tariffs that better align with current and projected costs.
- **Impact analysis for TOU rates in Ontario.** Measured the impacts of a system-wide Time of Use (TOU) deployment in the province of Ontario, Canada, on behalf of the Ontario Power Authority. To account for the lack of a designated control group, Brattle created a quasi-experimental design that took advantage of differences in the timing of the TOU rollout.
- **Measurement and evaluation for in-home displays, home energy controllers, smart appliances, and alternative rates for Florida Power & Light (FPL).** Carried out a 2-year impact evaluation of a dynamic and enabling technology pilot program. Used econometric methods to estimate the changes in load shapes, changes in peak demand, and changes in energy consumption for three different treatments. The results of this study were shared with Department of Energy to fulfill the data reporting requirements of FPL's Smart Grid Investment Grant.
- **Report examining the costs and benefits of dynamic pricing in the Australian energy market.** For the Australian Energy Market Commission (AEMC), developed a report that reviewed the various forms of dynamic pricing, such as time-of-use pricing, critical peak pricing, peak time rebates, and real-time pricing, for a variety of performance metrics including economic efficiency, equity, bill risk, revenue risk, and risk to vulnerable customers. It also discussed ways in which dynamic pricing could be rolled out in Australia to raise load factors and lower average energy costs for all consumers without harming vulnerable consumers, such as those with low incomes or medical conditions requiring the use of electricity.
- **Whitepaper on emerging issues in innovative pricing.** For the Regulatory Assistance Project (RAP), developed a whitepaper on emerging issues and best practices in innovative rate design and deployment. The paper included an overview of AMI-enabled electricity pricing options, recommendations for designing the rates and conducting experimental pilots, an

overview of recent pilots, full-deployment case studies, and a blueprint for rolling out innovative rate designs. The paper's audience was international regulators in regions that were exploring the potential benefits of smart metering and innovative pricing.

- **Assessing the full benefits of real-time pricing.** For two large Midwestern utilities, assessed and, where possible, quantified the potential benefits of the existing residential real-time pricing (RTP) rate offering. The analysis included not only "conventional" benefits such as avoided resource costs, but under the direction of the state regulator, was expanded to include harder-to-quantify benefits such as improvements to national security and customer service.
- **Pricing and technology pilot design and impact evaluation for Connecticut Light & Power (CL&P).** Designed the Plan-It Wise Energy pilot for all classes of customers and subsequently evaluated the Plan-It Wise Energy program (PWEP). PWEP tested the impacts of CPP, PTR, and time of use (TOU) rates on the consumption behaviors of residential and small commercial and industrial customers.
- **Dynamic pricing pilot design and impact evaluation: Baltimore Gas & Electric.** Designed and evaluated the Smart Energy Pricing (SEP) pilot, which ran for four years. The pilot tested a variety of rate designs including critical peak pricing and peak time rebates on residential customer consumption patterns. In addition, the pilot tested the impacts of smart thermostats and the Energy Orb.
- **Impact evaluation of a residential dynamic pricing experiment: Consumers Energy (Michigan).** Designed the pilot and carried out an impact evaluation with the purpose of measuring the impact of critical peak pricing (CPP) and peak time rebates (PTR) on residential customer consumption patterns. The pilot also tested the influence of switches that remotely adjust the duty cycle of central air conditioners.
- **Impact simulation of Ameren Illinois utilities' power smart pricing program.** Simulated the potential demand response of residential customers enrolled in real-time prices. The results of this simulation were presented to the Midwest ISO's Supply Adequacy Working Group (SAWG) to explore alternative ways of introducing price responsive demand in the region.
- **The case for dynamic pricing: Demand Response Research Center.** Led a project involving the California Public Utilities Commission, the California Energy Commission, the state's three investor-owned utilities, and other stakeholders in the rate design process. Identified key issues and barriers associated with the development of time-based rates. Revisited the fundamental objectives of rate design, including efficiency and equity, with a special emphasis on meeting the state's strongly-articulated needs for demand response and energy efficiency. Developed a score-card for evaluating competing rate designs and applied it to a set of illustrative rates that were created for four customer classes using actual utility data. The work was reviewed by a national peer-review panel.

- **Analyzed the economics of self-generation of steam.** Specified, estimated, tested, and validated a large-scale model that analyzes the response of some 2,000 large commercial customers to rising steam prices. The model includes a module for analyzing conservation behavior, another module for the probability of self-generation switching behavior, and a module for forecasting sales and peak demand.
- **Design and impact evaluation of the statewide pricing pilot: Three California utilities.** Working with a consortium of California's three investor-owned utilities to design a statewide pricing pilot to test the efficacy of dynamic pricing options for mass-market customers. The pilot was designed using scientific principles of experimental design and measured changes in usage induced by dynamic pricing for over 2,500 residential and small commercial and industrial customers. The impact evaluation was carried out using state-of-the-art econometric models. Information from the pilot was used by all three utilities in their business cases for advanced metering infrastructure (AMI). The project was conducted through a public process involving the state's two regulatory commissions, the power agency, and several other parties.
- **Economics of dynamic pricing: Two California utilities.** Reviewed a wide range of dynamic pricing options for mass-market customers. Conducted an initial cost-effectiveness analysis and updated the analysis with new estimates of avoided costs and results from a survey of customers that yielded estimates of likely participation rates.
- **Economics of time-of-use pricing: A Pacific Northwest utility.** This utility ran the nation's largest time-of-use pricing pilot program. Assessed the cost-effectiveness of alternative pricing options from a variety of different perspectives. Options included a standard three-part time-of-use rate and a quasi-real time variant where the prices vary by day. Worked with the client in developing a regulatory strategy. Worked later with a collaborative to analyze the program's economics under a variety of scenarios of the market environment.
- **Economics of dynamic pricing options for mass-market customers - Client: A multi-state utility.** Identified a variety of pricing options suited to meet the needs of mass-market customers, and assessed their cost-effectiveness. Options included standard three-part time-of-use rates, critical peak pricing, and extreme-day pricing. Developed plans for implementing a pilot program to obtain primary data on customer acceptance and load shifting potential. Worked with the client in developing a regulatory strategy.
- **Real-time pricing in California - Client: California Energy Commission.** Surveyed the national experience with real-time pricing of electricity, directed at large power customers. Identified lessons learned and reviewed the reasons why California was unable to implement real-time pricing. Cataloged the barriers to implementing real-time pricing in California, and developed a program of research for mitigating the impacts of these barriers.
- **Market-based pricing of electricity - Client: A large Southern utility.** Reviewed pricing methodologies in a variety of competitive industries including airlines, beverages, and automobiles. Recommended a path that could be used to transition from a regulated utility

environment to an open market environment featuring customer choice in both wholesale and retail markets. Held a series of seminars for senior management and their staff on the new methodologies.

- **Tools for electricity pricing - Client: Consortium of several U.S. and foreign utilities.** Developed Product Mix, a software package that uses modern finance theory and econometrics to establish a profit-maximizing menu of pricing products. The products range from the traditional fixed-price product to time-of-use prices to hourly real-time prices, and also include products that can hedge customers' risks based on financial derivatives. Outputs include market share, gross revenues, and profits by product and provider. The calculations are performed using probabilistic simulation, and results are provided as means and standard deviations. Additional results include delta and gamma parameters that can be used for corporate risk management. The software relies on a database of customer load response to various pricing options called StatsBank. This database was created by metering the hourly loads of about one thousand commercial and industrial customers in the United States and the United Kingdom.
- Risk-based pricing - Client: Midwestern utility. Developed and tested new pricing products for this utility that allowed it to offer risk management services to its customers. One of the products dealt with weather risk; another one dealt with the risk that real-time prices might peak on a day when the customer does not find it economically viable to cut back operations.

Demand Response

- **Combined heat and power generation study.** Investigated the economic potential for combined heat and power and regulatory policies to unlock that potential in a Middle Eastern country.
- **National action plan for demand response: Federal Energy Regulatory Commission.** Led a consulting team developing a national action plan for demand response (DR). The national action plan outlined the steps that need to be taken in order to maximize the amount of cost-effective DR that can be implemented. The final document was filed with U.S. Congress.
- **National assessment of demand response potential: Federal Energy Regulatory Commission.** Led a team of consultants to assess the economic and achievable potential for demand response programs on a state-by-state basis. The assessment was filed with the U.S. Congress, as required by the Energy Independence and Security Act.

- **Demand response program review for Integrated Resource Plan development.** In response to legislation requiring the Connecticut utilities to jointly prepare a 10-year integrated resource plan, we conducted the analysis and helped prepare the plan. In coordination with the two leading utilities in the state, we conducted a detailed analysis of alternative resource solutions (both supply- and demand-side), drafted the report, and presented it to the Connecticut Energy Advisory Board. The analysis involved a detailed review and critique of the companies' proposed DR programs.
- **Integration of DR into wholesale energy markets.** Developed a whitepaper, "Fostering Economic Demand Response in the Midwest ISO," evaluating alternative approaches to efficiently integrating DR into its energy markets while encouraging increased participation. This work involved interviewing market participants and analyzing several approaches to economic DR regarding economic efficiency, participation rates, operational fit with other ISO rules, and susceptibility to state-level and ISO-level implementation barriers. This work involved an extensive survey of DR programs (qualification criteria, bidding rules, incorporation into market clearing software, measurement and verification, and settlement) in ISO/ Regional Transmission Organization (RTO) markets around the country. The project also required a detailed review of existing DR program tariffs for utilities in the RTO's service territory and development of a matrix for summarizing the various characteristics of these programs.
- **Integration of DR into resource adequacy constructs.** For the Midwest ISO, assisted in developing qualification criteria for DR as a capacity resource (we also developed estimates of likely future contributions of DR to resource adequacy, for use by their transmission planning group). For PJM, as part of our review of its capacity market, we developed recommendations on how to treat DR comparably to generation resources while accounting for the special attributes of DR. Our recommendations addressed product definition, auction rules, and penalty provisions. For the Connecticut utilities in their integrated resource planning, we evaluated future resource needs given various levels of demand response programs.
- **Evaluation of the demand response benefits of advanced metering infrastructure: Mid-Atlantic utility.** Conducted a comprehensive assessment of the benefits of advanced metering infrastructure (AMI) by developing dynamic pricing rates that are enabled by AMI. The analysis focused on customers in the residential class and commercial and industrial customers under 600 kW load.
- **Estimation of demand response impacts: Major California utility.** Worked with the staff of this electric utility in designing dynamic pricing options for residential and small commercial and industrial customers. These options were designed to promote demand response during critical peak days. The analysis supported the utility's advanced metering infrastructure (AMI) filing with the California Public Utilities Commission. Subsequently, the commission

unanimously approved a $1.7 billion plan for rolling out nine million electric and gas meters based in part on this project work.

Smart Grid Strategy

- **Development of a smart grid investment roadmap for Vietnamese utilities.** For the five Vietnamese power corporations, developed a roadmap to guide future smart grid investment decisions. The report identified and described the various smart grid investment options, established objectives for smart grid deployment, presented a multi-phase approach to deploying the smart grid, and provided preliminary recommendations regarding the best investment opportunities. Also presented relevant case studies and an assessment of the current state of the Vietnamese power grid. The project involved in-country meetings as well as a stakeholder workshop that was conducted by Brattle staff.
- **Cost-benefit analysis of the smart grid: Rocky mountain utility.** Reviewed the leading studies on the economics of the smart grid and used the findings to assess the likely cost-effectiveness of deploying the smart grid in one geographical location.
- **Modeling benefits of smart grid deployment strategies.** Developed a model for assessing the benefits of smart grid deployment strategies over a long-term (e.g., 20-year) forecast horizon. The model, called iGrid, is used to evaluate seven distinct smart grid programs and technologies (e.g., dynamic pricing, energy storage, PHEVs) against seven key metrics of value (e.g., avoided resource costs, improved reliability).
- **Smart grid strategy in Canada.** The Alberta Utilities Commission (AUC) was charged with responding to a Smart Grid Inquiry issued by the provincial government. Advised the AUC on the smart grid, and what impacts it might have in Alberta.
- **Smart grid deployment analysis for collaborative of utilities.** Adapted the iGrid modeling tool to meet the needs of a collaborative of utilities in the southern U.S. In addition to quantifying the benefits of smart grid programs and technologies (e.g., advanced metering infrastructure deployment and direct load control), the model was used to estimate the costs of installing and implementing each of the smart grid programs and technologies.
- **Development of a smart grid cost-benefit analysis framework.** For the Electric Power Research Institute (EPRI) and the U.S. DOE, contributed to the development of an approach for assessing the costs and benefits of the DOE's smart grid demonstration programs.
- Analysis of the benefits of increased access to energy consumption information. For a large technology firm, assessed market opportunities for providing customers with increased access to real-time information regarding their energy consumption patterns. The analysis includes an assessment of deployments of information display technologies and analysis of the potential benefits that are created by deploying these technologies.
- **Developing a plan for integrated smart grid systems.** For a large California utility, helped to develop applications for funding for a project to demonstrate how an integrated smart grid

system (including customer-facing technologies) would operate and provide benefits.

Demand Forecasting

- **Electricity sales and peak demand forecasting study:** For a large electric utility in South-East Asia, Brattle provided consulting services that involved assessing the performance of their load forecasting methodology and developing new models that provided more accurate forecasts.
- **Electricity consumption and maximum demand forecasting:** For a medium-sized utility in Asia-Pacific, Brattle provided consulting services on forecasting electricity consumption and maximum demand. Our work focused on analyzing drivers of growth in electricity sales, reviewed model performance, identified best practices and provided recommended approaches for analyzing trends in electricity sales and load forecasting.
- **Forecasting review.** Evaluated and critiqued the process conducted by an Australian utility company's electricity market forecasting, including the forecasting of electricity demand, supply, and price.
- **Comprehensive review of load forecasting methodology. PJM Interconnection.** Conducted a comprehensive review of models for forecasting peak demand and re-estimated new models to validate recommendations. Individual models were developed for 18 transmission zones as well as a model for the RTO system.
- **Analyzed downward trend: Western utility.** Conducted a strategic review of why sales had been lower than forecast in a year when economic activity had been brisk. Developed a forecasting model for identifying what had caused the drop in sales and its results were used in an executive presentation to the utility's board of directors. Also developed a time series model for more accurately forecasting sales in the near term and this model is now being used for revenue forecasting and budgetary planning.
- **Analyzed why models are under-forecasting: Southwestern utility.** Reviewed the entire suite of load forecasting models, including models for forecasting aggregate system peak demand, electricity consumption per customer by sector and the number of customers by sector. Ran a variety of forecasting experiments to assess both the ex-ante and ex-post accuracy of the models and made several recommendations to senior management.
- **U.S. demand forecast: Edison Electric Institute.** For the U.S. as a whole, developed a base case forecast and several alternative case forecasts of electric energy consumption by end use and sector. Subsequently developed forecasts that were based on EPRI's system of end-use forecasting models. The project was done in close coordination with several utilities and some of the results were published in book form.
- **Developed models for forecasting hourly loads: Merchant generation and trading company.** Using primary data on customer loads, weather conditions, and economic activity, developed models for forecasting hourly loads for residential, commercial, and industrial customers for

three utilities in a Midwestern state. The information was used to develop bids into an auction for supplying basic generation services.

- **Gas demand forecasting system - Client: A leading gas marketing and trading company, Texas.** Developed a system for gas nominations for a leading gas marketing company that operated in 23 local distribution company service areas. The system made week-ahead and month-ahead forecasts using advanced forecasting methods. Its objective was to improve the marketing company's profitability by minimizing penalties associated with forecasting errors.

Demand-Side Management

- **The economics of biofuels.** For a western utility that is facing stringent renewable portfolio standards and that is heavily dependent on imported fossil fuels, carried out a systematic assessment of the technical and economic ability of biofuels to replace fossil fuels.
- **Assessment of demand-side management and rate design options: Large Middle Eastern electric utility.** Prepared an assessment of demand-side management and rate design options for the four operating areas and six market segments. Quantified the potential gains in economic efficiency that would result from such options and identified high priority programs for pilot testing and implementation. Held workshops and seminars for senior management, managers, and staff to explain the methodology, data, results, and policy implications.
- **Likely future impact of demand-side programs on carbon emissions - Client: The Keystone Center.** As part of the Keystone Dialogue on Climate Change, developed scenarios of future demand-side program impacts, and assessed the impact of these programs on carbon emissions. The analysis was carried out at the national level for the U.S. economy, and involved a bottom-up approach involving many different types of programs including dynamic pricing, energy efficiency, and traditional load management.
- **Sustaining energy efficiency services in a restructured market - Client: Southern California Edison.** Helped in the development of a regulatory strategy for implementing energy efficiency strategies in a restructured marketplace. Identified the various players that were likely to operate in a competitive market, such as third-party energy service companies (ESCO's) and utility affiliates. Assessed their objectives, strengths, and weaknesses and recommended a strategy for the client's adoption. This strategy allowed the client to participate in the new market place, contribute to public policy objectives, and not lose market share to new entrants. This strategy has been embraced by a coalition of several organizations involved in the California PUC's working group on public purpose programs.
- **Organizational assessments of capability for energy efficiency - Client: U.S. Agency for International Development, Cairo, Egypt.** Conducted in-depth interviews with senior executives of several energy organizations, including utilities, government agencies, and ministries to determine their goals and capabilities for implementing programs to improve

energy end-use efficiency in Egypt. The interviews probed the likely future role of these organizations in a privatized energy market, and were designed to help develop U.S. AID's future funding agenda.

- **Enhancing profitability through energy efficiency services - Client: Jamaica Public Service Company.** Developed a plan for enhancing utility profitability by providing financial incentives to the client utility, and presented it for review and discussion to the utility's senior management and Jamaica's new Office of Utility Regulation. Developed regulatory procedures and legislative language to support the implementation of the plan. Conducted training sessions for the staff of the utility and the regulatory body.

Advanced Technology Assessment

- **Competitive energy and environmental technologies - Clients: Consortium of clients, led by Southern California Edison, included the Los Angeles Department of Water and Power and the California Energy Commission.** Developed a new approach to segmenting the market for electrotechnologies, relying on factors such as type of industry, type of process and end-use application, and product size. Developed a user-friendly system for assessing the competitiveness of a wide range of electric and gas-fired technologies in more than 100 four-digit SIC code manufacturing industries and 20 commercial businesses. The system includes a database of more than 200 end-use technologies and a model of customer decision making.
- **Market infrastructure of energy-efficient technologies - Client: EPRI.** Reviewed the market infrastructure of five key end-use technologies, and identified ways in which the infrastructure could be improved to increase the penetration of these technologies. Data was obtained through telephone interviews with equipment manufacturers, engineering firms, contractors, and end-use customers

TESTIMONY

Arizona

- Rebuttal Testimony before the Arizona Corporation Commission on behalf of Arizona Public Service Company, in the matter of *Stacey Champion, et al., v Arizona Public Service Corporation*, Docket No. E-01345A-18-0002, August 17, 2018.
- Direct Testimony before the Arizona Corporation Commission on behalf of Arizona Public Service Company, in the matter of *Stacey Champion, et al., v Arizona Public Service Corporation*, Docket No. E-01345A-18-0002, July 31, 2018.
- Direct Testimony before the Arizona Corporation Commission on behalf of Arizona Public Service Company, in the matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed To Develop Such Return, Docket No. E-01345A-16-0036, June 1, 2016.

- Direct Testimony before the Arizona Corporation Commission on behalf of Arizona Public Service Company, in the matter of the Application for UNS Electric, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of UNS Electric, Inc. Devoted to the its Operations Throughout the State of Arizona, and for Related Approvals, Docket No. E-04204A-15-0142, December 9, 2015.

Arkansas

- Direct Testimony before the Arkansas Public Service Commission on behalf of Entergy Arkansas, Inc., in the matter of Entergy Arkansas, Inc.'s Application for an Order Finding the Deployment of Advanced Metering Infrastructure to be in the Public Interest and Exemption from Certain Applicable Rules, Docket No. 16-060-U, September 19, 2016.

California

- Rebuttal Testimony before the Public Utilities Commission of the State of California, Pacific Gas and Electric Company Joint Utility on Demand Elasticity and Conservation Impacts of Investor-Owned Utility Proposals, in the Matter of Rulemaking 12-06-013, October 17, 2014.
- Prepared testimony before the Public Utilities Commission of the State of California on behalf of Pacific Gas and Electric Company on rate relief, Docket No. A.10-03-014, Summer 2010.
- Qualifications and prepared testimony before the Public Utilities Commission of the State of California, on behalf of Southern California Edison, Edison SmartConnect™ Deployment Funding and Cost Recovery, exhibit SCE-4, July 31, 2007.
- Testimony on behalf of the Pacific Gas & Electric Company, in its application for Automated Metering Infrastructure with the California Public Utilities Commission. Docket No. 05-06-028, 2006.

Colorado

- Rebuttal testimony before the Public Utilities Commission of the State of Colorado in the Matter of Advice Letter No. 1535 by Public Service Company of Colorado to Revise its Colorado PUC No.7 Electric Tariff to Reflect Revised Rates and Rate Schedules to be Effective on June 5, 2009. Docket No. 09al-299e, November 25, 2009.
- Direct testimony before the Public Utilities Commission of the State of Colorado, on behalf of Public Service Company of Colorado, on the tariff sheets filed by Public Service Company of Colorado with advice letter No. 1535 – Electric. Docket No. 09S-__E, May 1, 2009.

Connecticut

- Testimony before the Department of Public Utility Control, on behalf of the Connecticut Light and Power Company, in its application to implement Time-of-Use, Interruptible Load Response, and Seasonal Rates- Submittal of Metering and Rate Pilot Results- Compliance Order No. 4, Docket no. 05-10-03RE01, 2007.

District of Columbia

- Direct testimony before the Public Service Commission of the District of Columbia on behalf of Potomac Electric Power Company in the matter of the Application of Potomac Electric Power Company for Authorization to Establish a Demand Side Management Surcharge and an Advance Metering Infrastructure Surcharge and to Establish a DSM Collaborative and an AMI Advisory Group, case no. 1056, May 2009.

Georgia

- Direct testimony before the State of Georgia Public Service Commission on behalf of Georgia Power Company, in the matter of Georgia Power Company's 2019 Base Rate Case, Docket No. 42516, June 28, 2019.

Idaho

- Rebuttal Testimony before the Idaho Public Utilities Commission on behalf of Idaho Power Company (Idaho Power), in the matter of the Application of Idaho Power Company for Authority to Establish New Schedules for Residential and Small General Service Customers with On-Site Generation, Case No. IPC-E-17-13, January 26, 2018.

Illinois

- Direct testimony on rehearing before the Illinois Commerce Commission on behalf of Ameren Illinois Company, on the Smart Grid Advanced Metering Infrastructure Deployment Plan, Docket No. 12-0244, June 28, 2012.
- Testimony before the Illinois Commerce Commission on behalf of Commonwealth Edison Company regarding the evaluation of experimental residential real-time pricing program, 11-0546, April 2012.

- Rebuttal Testimony before the Illinois Commerce Commission on behalf of Commonwealth Edison Company in the matter of the Petition to Approve an Advanced Metering Infrastructure Pilot Program and Associated Tariffs, No. 09-0263, August 14, 2009.
- Prepared rebuttal testimony before the Illinois Commerce Commission on behalf of Commonwealth Edison, on the Advanced Metering Infrastructure Pilot Program, ICC Docket No. 06-0617, October 30, 2006.

Indiana

- Direct testimony before the State of Indiana, Indiana Utility Regulatory Commission, on behalf of Vectren South, on the smart grid. Cause no. 43810, 2009.

Kansas

- Rebuttal testimony before the State Corporation Commission of the State of Kansas, on behalf of Westar Energy, in the matter of the Joint Application of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Services, Docket No. 18-WSEE-328-RTS, July 3, 2018.
- Direct testimony before the State Corporation Commission of the State of Kansas, on behalf of Westar Energy, in the matter of the Joint Application of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Services, Docket No. 18-WSEE-328-RTS, February 1, 2018.
- Reply affidavit before the State Corporation Commission of the State of Kansas, on behalf of Westar Energy, in the matter of the General Investigation to Examine Issues Surrounding Rate Design for Distributed Generation Customers, Docket No. 16-GIME-403-GIE, May 5, 2017.
- Direct testimony before the State Corporation Commission of the State of Kansas, on behalf of Westar Energy, in the matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in Their Charges for Electric Service, Docket No. 15-WSEE-115-RTS, March 2, 2015.

Louisiana

- Rebuttal testimony before the Council of the City of New Orleans on behalf of Entergy New Orleans, LLC, in the matter of Application of Entergy New Orleans, LLC for a Change in Electric and Gas Rates Pursuant to Council Resolutions R-15-194 and R-17-504 and for Related Relief, Docket No. UD-18-07, March 2019.
- Direct testimony before the Council for the City of New Orleans on behalf of Entergy New Orleans, LLC, in the matter of Application of Entergy New Orleans, LLC for a Change in Electric and Gas Rates Pursuant to Council Resolutions R-15-194 and R-17-504 and for Related Relief, Docket No. UD-18-07, July 2018.
- Direct testimony before the Louisiana Public Service Commission on behalf of Entergy Louisiana, LLC, in the matter of Approval to Implement a Permanent Advanced Metering System and Request for Cost Recovery and Related Relief in accordance with Louisiana Public Service Commission General Order dated September 22, 2009, R-29213, November 2016.

- Direct testimony before the Council of the City of New Orleans, on behalf of Entergy New Orleans, Inc., in the matter of the Application of Energy New Orleans, Inc. for Approval to Deploy Advanced Metering Infrastructure, and Request for Cost Recovery and Related Relief, October 2016.

Maryland

- Direct Testimony before the Maryland Public Service Commission, on behalf of Potomac Electric Power Company in the matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy, April 19, 2016.
- Rebuttal Testimony before the Maryland Public Service Commission on behalf of Baltimore Gas and Electric Company in the matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates, Case No. 9406, March 4, 2016.
- Direct testimony before the Public Service Commission of Maryland, on behalf of Potomac Electric Power Company and Delmarva Power and Light Company, on the deployment of Advanced Meter Infrastructure. Case no. 9207, September 2009.
- Prepared direct testimony before the Maryland Public Service Commission, on behalf of Baltimore Gas and Electric Company, on the findings of BGE's Smart Energy Pricing ("SEP") Pilot program. Case No. 9208, July 10, 2009.

Minnesota

- Rebuttal testimony before the Minnesota Public Utilities Commission State of Minnesota on behalf of Northern States Power Company, doing business as Xcel Energy, in the matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E002/GR-12-961, March 25, 2013.
- Direct testimony before the Minnesota Public Utilities Commission State of Minnesota on behalf of Northern States Power Company, doing business as Xcel Energy, in the matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E002/GR-12-961, November 2, 2012.

Mississippi

- Direct testimony before the Mississippi Public Service Commission, on behalf of Entergy Mississippi, Inc., in the matter of Application for Approval of Advanced Metering Infrastructure and Related Modernization Improvements, EC-123-0082-00, November 2016.

Missouri

- Direct testimony before the Missouri Public Service Commission, on behalf of Union Electric Company d/b/a Ameren Missouri, in the matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service, ER-2019-0335, July 3, 2019.

Montana

- Rebuttal testimony before the Public Service Commission of the State of Montana on behalf of NorthWestern Energy, in the matter of NorthWestern Energy's Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design, Docket No. D2018.2.12, April 2019.
- Prefiled direct testimony before the Public Service Commission of the State of Montana on behalf of NorthWestern Energy, in the matter of NorthWestern Energy's Application for Authority to Increase its Retail Electric Utility Service Rates and for Approval of its Electric Service Schedules and Rules, Docket No. D2018.2.12, September 28, 2018.

Nevada

- Prepared rebuttal testimony before the Public Utilities Commission of Nevada on behalf of Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy, in the matter of net metering and distributed generation cost of service and tariff design, Docket Nos. 15-07041 and 15-07042, November 3, 2015.
- Prepared direct testimony before the Public Utilities Commission of Nevada on behalf of Nevada Power Company d/b/a NV Energy, in the matter of the application for approval of a cost of service study and net metering tariffs, Docket No. 15-07, July 31, 2015.

New Mexico

- Direct testimony before the New Mexico Regulation Commission on behalf of Public Service Company of New Mexico in the matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 507, Case No. 14-00332-UT, December 11, 2014.

Oklahoma

- Rebuttal Testimony before the Corporation Commission of Oklahoma on behalf of Oklahoma Gas and Electric Company in the matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to modify its Rates, Charges and Tariffs for Retail Electric Service in Oklahoma, Cause No. PUD 201500273, April 11, 2016.
- Direct Testimony before the Corporation Commission of Oklahoma on behalf of Oklahoma Gas and Electric Company in the matter of the Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to modify its Rates, Charges and Tariffs for Retail Electric Service in Oklahoma, Cause No. PUD 201500273, December 18, 2015.

- Responsive Testimony before the Corporation Commission of Oklahoma on behalf of Oklahoma Gas and Electric Company in the matter of the Application of Brandy L. Wreath, Director of the Public Utility Division, for Determination of the Calculation of Lost Net Revenues and Shared Savings Pursuant to the Demand Program Rider of Oklahoma Gas and Electric Company, Cause No. PUD 201500153, May 13, 2015.

Pennsylvania

- Direct testimony before the Pennsylvania Public Utility Commission, on behalf of PECO on the Methodology Used to Derive Dynamic Pricing Rate Designs, Case no. M-2009-2123944, October 28, 2010.

Washington

- Pre-filed Direct Testimony before the Washington Utilities and Transportation Commission on Behalf of Puget Sound Energy, Dockets UE-151871 and UG-151872, February 25, 2016.

REGULATORY APPEARANCES

Arkansas

- Presented before the Arkansas Public Service Commission, "The Emergence of Dynamic Pricing" at the workshop on the Smart Grid, Demand Response, and Automated Metering Infrastructure, Little Rock, Arkansas, September 30, 2009.

Delaware

- Presented before the Delaware Public Service Commission, "The Demand Response Impacts of PHI's Dynamic Pricing Program" Delaware, September 5, 2007.

Kansas

- Presented before the State Corporation Commission of the State of Kansas, "The Impact of Dynamic Pricing on Westar Energy" at the Smart Grid and Energy Storage Roundtable, Topeka, Kansas, September 18, 2009.

Ohio

- Presented before the Ohio Public Utilities Commission, "Dynamic Pricing for Residential and Small C&I Customers" at the Technical Workshop, Columbus, Ohio, March 28, 2012.

Texas

- Presented before the Public Utility Commission of Texas, "Direct Load Control of Residential Air Conditioners in Texas," at the PUCT Open Meeting, Austin, Texas, October 25, 2012.

PUBLICATIONS

Books

- *Electricity Pricing in Transition*. Co-editor with Kelly Eakin. Kluwer Academic Publishing, 2002.
- *Pricing in Competitive Electricity Markets*. Co-editor with Kelly Eakin. Kluwer Academic Publishing, 2000.
- *Customer Choice: Finding Value in Retail Electricity Markets*. Co-editor with J. Robert Malko. Public Utilities Inc. Vienna. Virginia: 1999.
- *The Changing Structure of American Industry and Energy Use Patterns*. Co-editor with John Broehl. Battelle Press, 1987.
- *Customer Response to Time of Use Rates: Topic Paper I*, with Dennis Aigner and Robert T. Howard, Electric Utility Rate Design Study, EPRI, 1981.

Chapters in Books

- "Making the Most of the No Load Growth Business Environment," with Dian Grueneich. *Distributed Generation and Its Implications for the Utility Industry*. Ed. Fereidoon P. Sioshansi. Academic Press, 2014. 303-320.
- "*Arcturus*: An International Repository of Evidence on Dynamic Pricing," with Sanem Sergici. *Smart Grid Applications and Developments, Green Energy and Technology*. Ed. Daphne Mah, Ed. Peter Hills, Ed. Victor O. K. Li, Ed. Richard Balme. Springer, 2014. 59-74.
- "Will Energy Efficiency make a Difference," with Fereidoon P. Sioshansi and Gregory Wikler. *Energy Efficiency: Towards the end of demand growth*. Ed. Fereidoon P. Sioshansi. Academic Press, 2013. 3-50.
- "The Ethics of Dynamic Pricing." *Smart Grid: Integrating Renewable, Distributed & Efficient Energy*. Ed. Fereidoon P. Sioshansi. Academic Press, 2012. 61-83.
- "The Dynamics of New Construction Programs in the 90s: A Review of the North American Experience," with G.A. Wikler. *Proceedings of the 1992 Conference on New Construction Programs for Demand-Side Management*, May 1992.
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- "Innovative Methods for Conducting End-Use Marketing and Load Research for Commercial Customers: Reconciling the Reconciled," with G.A. Wikler, T. Alereza, and S. Kidwell. *Proceedings of the Fifth National DSM Conference*. Boston, MA, September 1991.

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- "Post-Modern Rate Design: The 'Secret Sauce' in Customer Engagement," presented at the Entergy Regulatory Conference, April 9, 2019.
- "Valuing and Compensating Distributed Energy Resources in ERCOT," with Ira Shavel and Yingxia Yang, prepared for the Texas Clean Energy Coalition, March 28, 2019.
- "2040: A Pricing Odyssey," presented at the EEI Spring Rates and Regulatory Affairs Committee Meeting, March 25, 2019.
- "Reinventing Demand Response for the Age of Renewable Energy," with Ryan Hledik, December 14, 2018.
- "Enabling Grid Modernization through Alternative Rates and Alternative Regulation," with Sanem Sergici and William P. Zarakas, presented at the Energy Policy Roundtable in the PJM Footprint, November 29, 2018.
- "Modernizing Distribution Tariffs for Households," presented to the Energy Consumers Association in Sydney, Australia, November 9, 2018.
- "The State of Electric Vehicle Home Charging Rates," with Ryan Hledik and John Higham, presented to Colorado PUC, October 2018.
- "Rate Design to Enable Flexible Loads," with Mariko Geronimo Aydin, presented at APPA Business & Financial Conference 2018, September 18, 2018.
- "Customer-driven Rate Design is the Wave of the Future," presented at the Colorado Rural Electric Association Managers Association Meeting, September 10, 2018.
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SANEM I. SERGICI

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Dr. Sanem Sergici is a Principal in The Brattle Group's Boston, MA office specializing in economic analysis of distributed energy resources (DERs); their impact on the distribution system operations and assessment of emerging utility business models and regulatory frameworks. She regularly assists electric utilities, regulators, law firms, and technology firms on matters related to innovative retail rate design, big data analytics, grid modernization investments, and alternative ratemaking mechanisms.

Dr. Sergici was part of the Brattle team advising the New York Department of Public Service Commissioners and led the development of a financial model to study the incentives required for and the impacts of incorporating large quantities of DERs on utility earnings and rates, during the early stages of the New York Reforming the Energy Vision (NYREV) initiative. Results of this model was instrumental in the development of key regulatory incentive mechanisms in NY. She has assisted several utility clients in developing short term and long term strategies involving new utility business models and regulatory frameworks enabling these models.

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 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 resource planning, development of load forecasting models and energy litigation.

Dr. Sergici is a frequent presenter on the economic analysis of DERs and regularly publishes in academic and industry journals. She was recently featured in Public Utility Fortnightly Magazine's "Fortnightly Under 40 2019" list. 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.

AREAS OF EXPERTISE

- Utility Regulatory and Business Models
- Innovative Rate Design and Impact Evaluation Studies
- Distributed Energy Resources
- Grid Modernization
- Resource Planning

EXPERIENCE

Utility Regulatory and Business Models

- Assisted the New York Department of Public Service to develop a comprehensive financial model of a representative (downstate) New York utility capable of demonstrating the impacts of REV initiatives upon utility financial performance. Our modeling effort included developing plausible incentive regulation frameworks, new incentive mechanisms, and potential platform frameworks, services and futures.

- Development of Performance Incentive Metrics for the Joint Utilities of New York. The Brattle Group worked with the New York PSC Staff and, subsequently, with the State's six investor owned electric utilities (Joint Utilities) in analyzing the feasibility and impacts associated with proposed earnings sharing mechanisms (EAMs), primarily the EAMs associated with load factor and system efficiency.

- Assisted a North American Utility with development of a short-term and long-term regulatory strategy to enable their 2030 Vision. Brattle team interviewed the executive team; identified consensus views and disagreements on alternative business models and regulatory models. Developed straw proposals for two potential regulatory models one focused on enabling shorter-term outcomes, and the other focused on enabling Company's longer-term vision.

- Assisted Pepco D.C. as they develop a multi-year rate plan and various traditional and emerging performance incentive metrics to be filed in their upcoming rate case. Brattle team developed and facilitated workshops to introduce Pepco's MYRP proposal to the stakeholders and assisted Pepco with incorporating stakeholder input to the final proposal.

- Assisted a Canadian Utility with a critical assessment of their custom incentive ratemaking model and discussed how it compares with other forms of PBR. We presented a jurisdictional scan of the PBR implementations across North America and Europe, and assessed pros and cons of each approach. We also advised them on currently proposed "Distributed Utility Models" and assess pros and cons of each model; reviewed "Alternative Regulatory Models" that were developed to ensure that utilities can coexist with the DERs and continue to maintain healthy balance sheets.

- For a Canadian electric utility, reviewed and summarized alternative regulatory frameworks and incentive models that would support a sustainable energy efficiency business. Investigated the pros and cons of these models, identified the implications of each model for the utility, and made a recommendation based on our findings. Utility will discuss the recommended approach with the regulator and seek an approval.
- For a large Canadian electric utility, assisted with the development of an alternative proposal to their current performance based regulation (PBR) framework. Examined and benchmarked several examples of performance based regulation schemes in place for other utilities, and advised on an enhanced PBR mechanism.

Innovative Rate Design and Impact Evaluation Studies

- Review of Rate Design Studies on Behalf of the Staff of the New Hampshire Public Utilities Commission. Brattle reviewed the rate design studies presented by Liberty Utilities and Eversource and filed testimony on behalf of the Staff. Both studies focused on the distribution services offered by the utilities and examined and testified on issues involving embedded and marginal cost based rate design. Dr. Sergici filed direct testimony in the proceeding.
- Design, measurement and verification of Maryland Joint Utilities' PC44 TOU pilot. Brattle serves as the technical lead on behalf of the Maryland Joint Utilities, and led the pilot design and M&V methodology work streams in the PC44 workgroup process. Brattle will evaluate results from these three pilots in 2020.
- Assisted a New Zealand distribution utility with development of a peak time rebate pilot. Advised the client in pilot design principles and calculated sample sizes to yield statistically significant results. Undertook empirical testing of more than 150 different baseline methods using the client data and recommended an approach that leads to the highest accuracy and lowest bias in predicting the event day usage.
- Developed a model for the Ontario Energy Board to estimate a counterfactual hourly customer demand profile for multiple innovative pricing profiles of interest. Evaluated the economic efficiency of each alternative pricing option, taking into account system cost drivers including energy, ancillary services, generation capacity, and transmission and distribution capacity, as well as overall changes to consumer welfare driven by induced changes in demand. This represents one of few efforts to fully quantify the societal costs and benefits of innovative rate structures and involved close collaboration with the OEB team to ensure the Ontario-specific market structures were accurately

reflected in our analysis.

- Technical Advisor to OEB on the New RPP Pilots. A Brattle team led by Dr. Sergici has developed a Technical Manual to guide the design and impact evaluation of new RPP pilots. Dr. Sergici has been closely working with the OEB RPP team as they oversee the implementation of these pilots in accordance with the guidelines

- Undertook impact Evaluation of Ontario's Time-of-Use Rates on Behalf of Ontario Power Authority. A Brattle team led by Dr. Sergici provided an impact evaluation of Ontario's province-wide roll-out of Time-of-Use (TOU) rates for its residential and general service customers on behalf of Ontario Power Authority. Brattle acquired hourly load data from the IESO and the LDCs, aggregated it for the pricing periods that correspond to the TOU rate, reinterpreted the full-scale deployment as a natural experiment, and analyzed it using econometric methods for three consecutive years.

- Undertook a retail rate benchmarking study for a large southwestern utility. Our team, led by Dr. Sergici, reviewed utility resource plans to estimate each utility's retail rate trajectory. We compared the utilities across a variety of rate drivers, such as reserve margin, fuel mix, load growth, load factor, renewables investment requirements, and demand-side activities, and provided strategic recommendations for addressing these drivers of future rate growth.

- Undertook an extensive review of the rate designs and methodologies used by other jurisdictions/countries for a large Canadian Utility. We reviewed the rates that are currently offered by a large Canadian utility and compared them with best industry practices from around the globe. As a result of our analysis, we identify some near term and long term alternative rate design options for our client, which can help them to manage revenue risks and volatility due to the effects of disruptive threats, and at the same time to increase innovation and affordability in the rate options presented to the customers.

- Assisted Pepco Holdings, Inc. to evaluate the effectiveness of the AMI-enabled energy managements tools (EMTs) in reducing per capita energy use. Led a team of four researchers to compile and process data for four of the PHI jurisdictions; identify relevant control groups and methodology for impact evaluation and undertake an econometric analysis to quantify the EMT impact.

- Assisted an industry-leading provider of integrated demand response, energy efficiency, and customer engagement solutions in the design of and M&V plan for a behavioral demand response program. The plan included a detailed section on sampling selection for statistically valid and detectable program impact results.

- Prepared a comprehensive blueprint document for measuring the impacts of Baltimore Gas and Electric Company's Smart Grid Customer Programs. BGE has started deploying smart meters to all of its residential customers in Spring of 2012 and is scheduled to complete the deployment over a three-year period. BGE developed a full-scale program, "Smart Energy Manager (SEM)" program, to meet a central objective of the Smart Grid Initiative - customer education and engagement in a Smart Grid environment. The blueprint documented the design elements of the SEM program and introducing the approaches that will be used to measure the impacts of different SEM tools once the program is in the field and sufficient data are collected.

- Measurement and evaluation for in-home displays, home energy controllers, smart appliances and alternative rates for FPL. Carried out a 2-year impact evaluation of a dynamic and enabling technology pilot program. Used econometric methods to estimate the changes in load shapes, changes in peak demand, and changes in energy consumption for three different treatments. The results of this study were shared with Department of Energy as to fulfill the data reporting requirements of FPL's Smart Grid Investment Grant.

- Pricing and technology pilot design and interim impact evaluation for Commonwealth Edison Company (ComEd). Assisted ComEd in the design of an ambitious pilot program that included approximately 25 different treatment cells. The pilot, which is the first "opt-out" pilot program of its kind, involved 8,000 customers and tested the impact of dynamic prices with and without customer education, informational feedback through basic and advanced feedback devices, and other enabling technologies in the summer of 2010. Conducted an interim impact evaluation study preceding the formal impact evaluation of the study, which is planned to be completed by the end of 2011.

- Pricing and technology pilot design and impact evaluation for Consumers Energy. Designed Consumers Energy's pricing and technology pilot and conducted the impact evaluation study after the pilot was completed in September 2010. The pilot tested critical peak pricing (CPP) and peak time rebates (PTR) in conjunction with information treatment and technology. The pilot also tested the potential "Hawthorne bias" for a group of control group customers who were aware of their involvement in the pilot.

- Member of a Technical Advisory Group (TAG), which was formed by Department of Energy (DOE) and Lawrence Berkeley National Laboratory (LBNL). Reviewed and provided feedback on the experimental designs of the utilities that were awarded Smart Grid Investment Grant projects and participated in periodic project review meetings with utilities to review and provide feedback on the interim results as they implement their projects. As part of this assignment, authored a guidance document that discussed different impact evaluation methods, which can be selected by the utilities. This document was shared with the utilities and other TAG members.

- For an Independent System Operator (ISO), designed, managed and analyzed a market research to help improve participation in retail electricity products that encourage price-responsive demand (PRD). The research determined customer preferences for various time-based pricing products that would help define PRD products that may be developed in the ISO for each customer class. ISO will use the results of this research to assist in modifying wholesale market design to better support such PRD products.

- Assisted a client in conceptually developing a new product that would increase customer participation and performance in energy efficiency (EE) and demand response (DR) programs. Developed Total Resource Cost (TRC) tests for a few targeted EE and DR programs, and modeled the benefits and costs with and without the client's new product offering

- Co-authored a whitepaper reviewing the results from five recent pilot and full-scale programs that investigated low-income customer price-responsiveness to dynamic prices. The core finding of the whitepaper is that low income customers are responsive to dynamic rates and that many such customers can benefit even without shifting load.

- For a large California utility, conducted an econometric analysis, which investigated the role of weather conditions, smart meter installations, and electricity rate increases, among other control variables, in explaining the changes in the monthly usages and bills of a group of complaining customers. Estimated pooled regressions using a panel dataset, as well as individual customer regressions for more than 1,000 customers.

- Assisted an Illinois electric utility in the assessment of alternative baseline calculation for implementing peak time rebate (PTR) programs. Under a PTR program, participants receive a cash rebate for each kWh of load that they reduce below their baseline usage during the event hours. This requires establishment of a baseline load from which the reductions can be computed. The analysis involved simulating baselines for more than

2,000 customers using five alternative methodologies for several event days. Identified and recommended the baseline calculation methodology that yielded the most accurate baseline for individual customers, through the use of MAPE and RMSE statistics.

- Evaluated the Plan-It Wise Energy program (PWEP) of Connecticut Light and Power (CL&P) Company. PWEP tested the impacts of critical peak pricing (CPP), peak time rebates (PTR), and time of use (TOU) rates on the consumption behaviors of residential and small commercial customers. Each rate design was tested with high and low price variation as well as with and without enabling technologies. Conducted an econometric analysis to determine weather dependent substitution and daily price elasticities and subsequently quantified demand and energy impacts for each of the treatments tested in the PWEP. Developed optimal rate designs to be adopted in a full deployment scenario.
- For Baltimore Gas and Electric Company, assisted in the preparation of direct and rebuttal expert testimonies before the Maryland Public Service Commission, that explain the design and results of 2008 and 2009 Smart Energy Pricing (SEP) pilots.
- Evaluated the Smart Energy Pricing (SEP) pilot program of Baltimore Gas and Electric Company for three consecutive years. The pilot was designed to quantify the impacts of critical peak pricing (CPP) and peak time rebates (PTR) on residential customer consumption patterns. Conducted an econometric analysis to estimate demand systems and predict substitution and daily price elasticities for participating customers. Using the parameters of the demand equations, quantified demand, energy, and bill impacts associated with the programs. Impacts of the socio-demographic characteristics of the participants as well as their ownership of enabling technologies were separately identified on the demand response of the program participants.
- Co-authored a business practice manual for forecasting price responsive demand (PRD) in Midwest ISO. The draft manual introduces different methodologies for measuring and incorporating PRD into forecast LSE requirement for LSEs that are at different stages of rolling-out their out their dynamic pricing programs. The draft manual also proposes methodologies for the verification of the forecasted demand net of PRD for long term planning purposes.
- Assisted in the development of an affidavit that evaluates the implications of PJM's proposed revisions to the Operating Agreement (OA) on barriers to participation in PJM's Economic and Emergency Load Response programs.

- Co-authored a whitepaper on "Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets" for Institute for Electric Efficiency. Whitepaper is intended to help facilitate nationwide progress toward the deployment of dynamic pricing of electricity by summarizing information that may assist utilities and regulators who are assessing the business case for advanced metering infrastructure (AMI).
- Assisted a New York utility in benchmarking their existing Demand Response (DR) portfolio to the best practice in U.S. and recommended improvements in their planned DR portfolio. Also assisted the utility in quantifying costs and benefits of pilot programs proposed in their DR filing before the State of New York Public Service Commission.
- Assisted an electric utility in developing a residential pricing pilot program that tests inclining- block rate (IBR) structure. More specifically, designed several revenue neutral IBR alternatives and quantified load reduction and bill impacts from these IBR rates.
- Assisted an electric utility in their dynamic rate design efforts. Conducted impact analyses of converting from a flat rate design to alternative dynamic rate designs for each of the five major customer rate classes of the utility. Developed models that allow simulation of energy, demand, and bill impacts by season, day type and time period for an average customer from each of customer classes.
- Simulated the potential demand response of an Illinois utility's residential customers enrolled in real time prices. Results of this simulation were used in recent Midwest ISO Supply Adequacy Working Group (SAWG) meeting to facilitate conversation about price responsive demand in the region. Simulations were run for different scenarios including historic versus spiky real-time prices; peak versus uniform allocation of capacity charges; and with and without enabling technologies.
- Designed a survey on Long-run Drivers of U.S. Energy Efficiency and Demand Response Potential on behalf of EPRI and EEI. Conducted statistical analyses to examine the survey responses, which were turned in by more than 300 power industry leaders and academic experts. Using the outcomes from this survey, assisted in the development of future scenarios to model energy efficiency and demand response impact through 2030.
- Assisted in the preparation of an EEI report that quantifies the benefits to consumers and utilities of dynamic pricing. Undertook a comprehensive review of the dynamic pricing programs across the U.S. and elsewhere. Also implemented price response simulations to quantify the likely peak demand reductions that would realize under alternative

dynamic pricing schemes.

Distributed Energy Resources and Grid Modernization

- For a U.S. utility, reviewed the utility's benefit cost assessment model used to evaluate distributed energy resources for alignment with commission orders and staff guidance. The assessment identified areas for refinement, including increasing the temporal and geographic granularity of the model. As part of the review, the Brattle team provided insights into potential misalignments between the valuation of transmission and distribution investment deferral within the model, customer value, and system value. The Brattle team rebuilt the model from the ground-up to allow for intuitive use and ensure that assumptions are clearly articulated and well-documented.
- For a large east-coast utility, reviewed benefit cost framework and model data to evaluate non-pipe options. The review included treatment of geographic differences in marginal costs due to pipeline access, and the Brattle team rebuilt the model from the ground-up to allow for intuitive use.
- System Dynamics Modeling of DER Adoption and Utility Business Impacts. Led the development of Brattle's Corporate Risk Integrated Strategy Platform (CRISP) model and assisted utility clients with the implementation of this model. CRISP is based on System Dynamics approach, which creates simulations based on dynamic feedbacks between utility policies and customer behavior, providing a new perspective on how much and how fast the "utility of the future" must evolve. The focus of these modeling efforts was to help utilities anticipate and accommodate distributed energy resources (DERs) as they become more economical and more widely adapted by retail electricity customers, and to evaluate the sustainability of their traditional cost-of-service business model in the face of such trends.
- Co-led a study for EPRI that analyzed a variety of approaches to representing DERs in utility planning models. Started with energy efficiency as the first DER to be analyzed, and undertook a comprehensive literature review to capture the complete range of options for evaluating EE in IRPs. Next, quantitatively evaluated the impact of the EE modeling method on important IRP objectives such as minimizing total resource costs, meeting environmental goals, and avoiding suboptimal resource planning decisions.
- Estimated NEM cross-subsidies using data from sixteen utilities. Used cost-of-service methodology to compare NEM customers costs on the system vs. revenue collection from these customers using company COS studies, and supplementing it by publicly available data on solar PV production profiles, installed DG capacity by utility and system load

profiles.

- Wrote a comprehensive report for National Electrical Manufacturer's Association (NEMA) that reviews most recently approved 10 major grid modernization projects. Report discusses business cases and cost recovery mechanisms for each of these projects and documents how grid modernization technologies have benefitted customers and utilities.
- Analyzed the impacts of electric utility infrastructure investment on system reliability and resiliency for a Northeastern Utility, following major weather events. Primary area of analysis involved estimation of economic value of investments to customers using value of lost load (VOLL) metrics for electric system investments.
- Assisted Pepco Holdings, Inc. to analyze the Phase I of its Conservation Voltage Reduction (CVR) program in its Maryland Service Territory. First of its kind, this econometric study compares consumption of the treatment and control groups before and after the implementation of CVR. More specifically, a regression analysis was conducted to compare the usage levels of treatment and control group customers to determine whether the CVR treatment resulted in statistically significant conservation and peak demand impacts. The analysis accounts for exogenous factors such as weather, calendar and seasonality impacts as well as utility energy and demand savings programs.

Resource Planning

- Led the Brattle team that assisted the New York City Mayor's Office of Sustainability with the development of New York City's Roadmap to 80 x 50. The Brattle team analyzed the change in energy-sector greenhouse gas (GHG) emissions resulting from more than six future scenarios. These scenarios explored the impacts of aggressive energy efficiency efforts, off-shore wind, and the continuance of low natural gas prices on the emissions footprint of New York City. The analysis shows that in order to reach 80 x 50, New York City will need to achieve a significant portion of its GHG reductions as a result of a dramatic shift towards a renewables-based grid. This shift towards renewables must overcome the anticipated retirement of nuclear facilities prior to 2050 and will be supported by the implementation of New York State's Clean Energy Standard and the declining cost of renewable energy.
- Conducted a study involving "solar to solar" comparison of equal amounts of residential- and utility-scale PV solar deployed in Xcel Energy Colorado's Service Area. Calculated costs and benefits of each of these two different but equally sized solar options, i.e.,

avoided energy, capacity and distribution network costs and others. The study found carbon reductions were greater on utility scale systems because the solar energy per MW is much higher on utility-scale due to better placement and tracking capability.

- Advised Nova Scotia Power Inc. on the reasonableness of the DSM scenarios and strategies that are being modeled in their Integrated Resource Plan (IRP). This effort also involved advising the Company on a variety of DSM issues and building up a model that quantifies the rate impacts for program participants and non-participants based on the selected DSM scenario.
- Coauthored the State's Annual Integrated Resource Plan (IRP) for the Connecticut Department of Energy and Environmental Protection (DEEP). This effort involved development of scenarios and strategies for an electric system to meet long-range electric demand while considering the growth of renewable energy, energy efficiency, other demand-side resources. Led the development of demand side management and emerging technology resource strategies and analyses involving these resources.
- Developed a model to assess the prudence of an electric utility's power procurement strategy in comparison to several other alternative options. As a result of this model, she assessed whether it is prudent to recover the congestion and loss costs associated with utility's chosen strategy from ratepayers in a state regulatory proceeding.
- Assisted in preparation of a marginal cost study for an integrated electric utility. The study estimated the incremental costs to the utility of serving additional demand and customer by time period, sub-region, and customer class. The costs were identified as energy, capacity and customer related for generation, transmission, and distribution systems of the utility.
- Assisted in developing an integrated resource plan for major electric utilities. Contributed to the design of future scenarios against which the resource solutions were evaluated. Designed scenarios were driven by external factors including fuel prices, load growth, generation technology capital costs, and changes in environmental regulations. Forecasted the inputs series for the resource planning model consistent with each of the designed scenarios.

Demand Forecasting

- For an Asian utility considering an investment on a generation plant in PJM, we have reviewed, replicated, and developed alternative load forecasts using PJM's 2017 update.

We have determined several uncertainty factors that are not fully captured in PJM's forecasting framework and developed "low load" and "high load" scenarios after accounting for these factors.

- For an electric utility in the Southeast, reviewed load forecasting models for residential and commercial customer classes. Assessed the accuracy and validity of the models by reviewing the historic and forecast period inputs to the model; model specification; in-sample and out-of- sample accuracy statistics; and incorporation of DSM impacts to the model, among many others. Also conducted an analysis using the U.S. Energy Information Administration's Annual Energy Outlook (AEO) data to determine the forecast errors during pre and post-recession periods.
- Developed a blueprint for integrating energy efficiency program impacts into the load forecasts for a Canadian Utility. This effort involved estimating the future impact of energy efficiency programs to be included in the load forecasts and developing price elasticity estimates that can be used to forecast the impact of the future changes in the price of electricity.
- Developed a load forecasting model for the pumping load of California State Water Project. Identified the main drivers of pumping load in major pumping stations. Through Monte Carlo simulations, quantified the uncertainty around load forecasts.
- Assisted in the preparation of testimony that evaluates the reasonableness of Florida Power and Light Co.'s total customer and monthly net energy for load (NEL) forecasting models. In addition to evaluating the methodology, also reviewed the reasonableness of the inputs used in the historic and forecast periods and assessed the soundness of ex-post adjustments made to the forecasts.
- Assisted PJM in the evaluation of its models for forecasting peak demand and re-estimated new models to validate recommendations. Predicted forecasting errors of the existing models and helped improving the forecast methodology by introducing the state-of-the art estimation techniques. Individual models were developed for 18 transmission zones as well as a model for the entire PJM system.
- Assisted a large utility in New York in understanding the decline in electric sales during the recent past and attributed the decline to a change in customer expectations of future income, based on declining consumer confidence that has been created by the lingering economic recession.

- Reviewed the structure of the Tennessee Valley Authority's energy sales forecasting models by sector, assessed the magnitudes of the price elasticities and the model specifications used to generate them, analyzed the ability of the models to generate a baseline forecast that could serve as a point of reference when evaluating the likely impacts and cost-effectiveness of a wide range of new energy efficiency and demand response programs.
- Developed a demand forecast model for one of the world's largest steam system operators. Estimated regression models to predict the price elasticities and switching behavior of different consumer classes. Also helped in the development of a model to forecast the impact of alternative steam tariffs on the consumption and switching patterns of consumers.

Energy Litigation and Market Power Analysis

- For the California Parties, provided Brattle witness with litigation support and testimony regarding manipulation of electric power and natural gas prices in the western U.S. during 2000-01. The proceeding, before the Federal Energy Regulatory Commission involved Enron, Dynegy, Mirant, Reliant, Williams, Powerex and many other suppliers in the U.S. and Canada.
- Part of a Brattle team that analyzed the impacts of a merger, involving FirstEnergy and West Penn Power, on competition in retail electricity markets on behalf of Brattle testifying expert Mr. Frank Graves. Both companies owned electric distribution companies, transmission assets, generation resources, and retail electricity providers in several Mid-Atlantic States. The analysis involved assessment of whether the increased market share in wholesale energy markets affects retail competition, the number of suppliers in retail electricity markets, the ease of entry and exit to provide electricity to retail customers directly or through default service procurements, and the potential for abusing affiliate relationships with the electric distribution company to favor the retail electricity provider affiliate.
- Assisted in preparing affidavit before the Federal Energy Regulatory Commission examining whether the proposed acquisition of a power plant by an electric utility would lead to anti-competitive effects on wholesale market competition. In addition to performing market

power tests required by FERC, directed an analysis that investigates the historical electric trading patterns between the acquiring utility and the other parties in the relevant geographical market. FERC agreed with the conclusion of the affidavit and authorized the transaction.

- Assisted in the development of testimony before the Postal Rate Commission involving calculation of mail processing variabilities and data quality issues. Addressed the endogeneity problems in the estimation of the variabilities using the instrumental variables approach.

OTHER PROFESSIONAL EXPERIENCE

- Taught Microeconomics for one year at Northeastern University. Also worked as a Research Assistant to Prof John Kwoka of Northeastern University on different utility industry projects.
- Worked as an adjunct research assistant for American Public Power Association and conducted an extensive literature survey on 'Time-of-Use (TOU) Pricing in Electric Utility Industry.

ACADEMIC HONORS AND FELLOWSHIPS

- Excellence in Economics Award, Northeastern University, 2008
- Member, The Honor Society of Phi Kappa Phi
- Graduate Fellowship & Tuition Scholarship, Northeastern University, 2003-2007
- Tuition scholarship and stipend from the Turkish Ministry of Education towards the completion of B.S. Degree in Economics, 1999-2003
- Turkish Government Scholarship Examination, ranked 1st among 600,000 students in 1995

TECHNICAL AND EXPERT REPORTS

1. *Energy Efficiency Administrator Models: Relative Strengths and Impact on Energy Efficiency Program Success,* with Nicole Irwin, prepared for Uplight, November 2019.
2. *Incorporating Distributed Energy Resources into Resource Planning: Energy Efficiency*, with Ryan Hledik, D.L. Oates, Tony Lee, and Jill Moraski, prepared for EPRI, May 2019.

3. *Status of DSM Cost Recovery and Incentive Mechanisms,* with Ahmad Faruqui, Elaine Cunha, and John Higham, prepared for Baltimore Gas & Electric, February 20, 2019.

4. "*Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates: Response to PC51 Request for Comments*," W. Zarakas, S. Sergici, P. Donohoo-Vallett, and N. Irwin, prepared for Joint Utilities of Maryland and filed in support of comments in PC51 for the Maryland Public Utilities Commission. March 29, 2019.

5. *U.S. Alternative Regulatory Mechanisms: Scope, Status and Future,* with William Zarakas and Pearl Donohoo-Vallett, prepared for Baltimore Gas & Electric, Delmarva Power & Light and Pepco, February 19, 2019.

6. *A Review of Pay for Performance (P4P) Programs and M&V 2.0*, with Heidi Bishop and Ahmad Faruqui, prepared for Commonwealth Edison, July 20, 2018.

7. *Reviewing the Business Case and Cost Recovery for Grid Modernization Investments,* with Michelle Li and Rebecca Carroll, prepared for National Electrical Manufacturers Association (NEM), 2018.

8. *Pepco Maryland In-Home Display Pilot Analysis*, with Ahmad Faruqui, prepared for Pepco, June 2017.

9. *80x50 Energy Sector Model Assumptions and Results,* with Michael Kline and Pearl Donohoo-Vallett, prepared for the Mayor's Office of Sustainability, January 4, 2017.

10. *Impact Evaluation of Pepco District of Columbia's Portfolio of Energy Management Tools,* with Ahmad Faruqui and Kevin Arritt, prepared for Pepco District of Columbia, October 2016.

11. *Impact Evaluation of Delmarva Maryland's Portfolio of Energy Management Tools,* with Ahmad Faruqui and Kevin Arritt, prepared for Delmarva Maryland, April 2016.

12. *Impact Evaluation of Pepco Maryland's Portfolio of Energy Management Tools,* with Ahmad Faruqui and Kevin Arritt, prepared for Pepco Maryland, January 2016.

13. *Impact Evaluation of Pepco Maryland's Phase I Conservation Voltage Reduction (CVR) Program,* with Ahmad Faruqui and Kevin Arritt, prepared for Pepco Maryland, July 2015.

14. *Analysis of Ontario's Full Scale Roll-out of TOU Rates – Final Study,* with Neil Lessem, Ahmad Faruqui, Dean Mountain, Frank Denton, Byron Spencer, and Chris King, prepared for Independent Electric System Operator, February 2016.
   http://www.ieso.ca/Documents/reports/Final-Analysis-of- Ontarios-Full-Scale-Roll-Out-of-TOU-Rates.pdf

15. *Comparative Generation Costs of Utility-Scale and Residential Scale PV in Xcel Energy*

Colorado's Service Area, with Bruce Tsuchida, Bob Mudge, Will Gorman, Peter Fox-Penner and Jens Schoene (EnernNex), prepared for First Solar, July 2015.

16. *Quantifying the Amount and Economic Impacts of Missing Energy Efficiency in PJM's Load Forecast,* with Ahmad Faruqui and Kathleen Spees, prepared for The Sustainable FERC Project, September 2014.

17. *Assessment of Load Factor as a System Efficiency Earning Adjustment Mechanism*, with William Zarakas, Kevin Arritt, and David Kwok, prepared for The Joint Utilities of New York, February 2017.

18. *Expert Declaration in a Patent Dispute Case involving a Demand Response Product,* July 2014. San Francisco.

19. *Measurement and Verification Principles for Behavior-Based Efficiency Programs, with Ahmad Faruqui, prepared for Opower,* May 2011. http://opower.com/uploads/library/file/10/brattle_mv_principles.pdf

20. *Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets,* with Ahmad Faruqui and Lisa Wood, IEE Whitepaper, June 2009.

21. *"The Impact of Dynamic Pricing on Low Income Customers,"* with Ahmad Faruqui and Jennifer Palmer, IEE Whitepaper, June 2010.

PUBLICATIONS

1. "Top Performing States in Energy Efficiency: Top States' Secret Sauce," *Public Utilities Fortnightly*, March 2020.

2. "Quantifying Net Energy Metering Subsidies," with Yingxia Yang, Maria Castaner, and Ahmad Faruqui, *The Electricity Journal*, Volume 32, Issue 8, October 2019.

3. "Arcturus 2.0: A Meta-analysis of Time-varying Rates for Electricity," with Ahmad Faruqui and Cody Warner, *The Electricity Journal*, Volume 30, Issue 10, December 2017.

4. "Do Manufacturing Firms Relocate in Response to Rising Electric Rates?" with Ahmad Faruqui, *Energy Regulation Quarterly*, Volume 5, Issue 2, June 2017.

5. "Dynamic Pricing Works in a Hot, Humid Climate," with Ahmad Faruqui and Neil Lessem, *Public Utilities Fortnightly*, May 2017.

6. "The impact of AMI-enabled conservation voltage reduction on energy consumption and peak demand," with Kevin Arritt and Sanem Sergici, *The Electricity Journal*, 30:2, March 2017, pp. 60-65. http://www.sciencedirect.com/science/article/pii/S1040619016302536

7. "Integration of residential PV and its implications for current and future residential electricity demand in the United States," with Derya Eryilmaz, *The Electricity Journal*, 29 (2016) 41-52.

8. "Impact Measurement of Tariff Changes when Experimentation is not an Option – A case study of Ontario, Canada," with Sanem Sergici, Neil Lessem, and Dean Mountain, *Energy Economics*, 52, December 2015, pp. 39-48.

9. "Utility Investments in Resiliency: Balancing Benefits with Cost in an Uncertain Environment," by William Zarakas, Sanem Sergici et al., *The Electricity Journal*, Volume 27, Issue 5, June 2014.

10. "Low Voltage Resiliency Insurance: Ensuring Critical Service Continuity during Major Power Outages," by William Zarakas, Frank Graves and Sanem Sergici, *Public Utilities Fortnightly*, September 2013.

11. "Arcturus: International Evidence on Dynamic Pricing," by Sanem Sergici and Ahmad Faruqui, *The Electricity Journal*, 26:7, August/September 2013, pp. 55-65.
12. "Dynamic Pricing of Electricity for Residential Customers: The Evidence from Michigan," by Ahmad Faruqui, Sanem Sergici and Lamine Akaba, *Energy Efficiency*, 6:3, August 2013, pp. 571–584.

13. "Dynamic Pricing of Electricity in the Mid-Atlantic Region: Econometric Results from the Baltimore Gas and Electric Company Experiment," by A. Faruqui and S. Sergici, *Journal of Regulatory Economics*, 27(3), 235–262.

14. "The Untold Story of: A Survey of C&I Dynamic Pricing Pilot Studies," with Ahmad Faruqui and Jenny Palmer, *Metering International*, Issue 3, 2010.

15. Divestiture policy and operating efficiency in U.S. electric power distribution," by John E. Kwoka, Jr., Michael Pollitt, and Sanem Sergici, *Journal of Regulatory Economics*, June 2010.

16. "Household Response to Dynamic Pricing of Electricity – A Survey of the Experimental Evidence," with Ahmad Faruqui, *Journal of Regulatory Economics*, October 2010.

17. "Rethinking Prices," with Ahmad Faruqui and Ryan Hledik, *Public Utilities Fortnightly*, January 2010.

18. "Piloting the Smart Grid," with Ahmad Faruqui and Ryan Hledik, *The Electricity Journal*, August/September 2009.

19. "The Impact of Informational Feedback on Energy Consumption - A Survey of the Experimental Evidence," with Ahmad Faruqui and Ahmed Sharif, *Energy-The International Journal*, August 2009.

20. "Three Essays on U.S. Electricity Restructuring," Unpublished Ph.D. Thesis, Northeastern University, August 2008.

PRESENTATIONS

1. "Policies in Support of Customers' Purchase of Renewable Energy," presented at the NARUC Annual Meeting & Education Conference, November 18, 2019.

2. "Rate Reform in Evolving Energy Marketplace," presented at EUCI Residential Demand Charges/TOU Summit, May 30, 2019.

3. "Grid Modernization: Policy, Market Trends and Directions Forward," presented at the 4th Annual Grid Modernization Forum, Chicago, IL, May 21, 2019.

4. "Accelerating the Renewable Energy Transformation: Role of Green Power Tariffs and Blockchain," presented to EUCI Southeast Clean Power Summit, February 25, 2019.

5. "The Case for Alternative Regulation and Unintended Consequences of Net Energy Metering," presented to the 46th Annual PURC Conference, Gainesville, FL, February 21, 2019

6. "Reviewing Grid Modernization Investments: Summary of Recent Methods and Projects," presented to the National Electrical Manufacturers Association (NEMA), December 4, 2018.

7. "Enabling Grid Modernization Through Alternative Rates and Alternative Regulation," presented at the Energy Policy Roundtable in the PJM Footprint, November 29, 2018.

8. "Return of Pay-for-Performance Stronger with M&V 2.0," prepared for BECC Conference, Innovations in Models, Metrics, and Customer Choice, Washington DC, October 2018.

9. "Rate Design in a High DER Environment," presented at MEDSIS Rate Design Workshop, Washington DC, September 2018.

10. "Demand Response for Natural Gas Distribution," presented at the Center for Research in Regulated Industries (CRRI) 31st Annual Western Conference, Monterey CA, June 2018.

11. "Status of Restructuring: Wholesale and Retail Markets," presented at the National Conference of State Legislatures Workshop, "Electricity Markets and State Challenges," Indianapolis IN, June 2018.

12. "Dynamic Pricing Works in a Hot and Humid Climate: Evidence from Florida," presented at the International Energy Policy & Programme Evaluation Conference, Bangkok Thailand, November 2017.

13. "Understanding Residential Customer Response to Demand Charges: Present and Future," presented at the EUCI Residential Demand Charges Conference, Chicago IL, October 2016.

14. "Utility Leaders Workshop: An Evolving Utility Business Model for the Caribbean," presented at the Caribbean Renewable Energy Forum, Miami FL, October 2016.

15. "Impact of Residential PV Penetration on Load Growth Expectations," presented at the AEIC Western Load Research Conference, September 2016.

16. "Moving away from Flat Rates," presented to Smart Grid Consumer Collaborative, Chicago, IL, September 2016.

17. "Residential Demand Charges: An Overview," presented at the EUCI Demand Charge Conference, Phoenix AZ, June 2016.

18. "Conservation Voltage Reduction Econometric Impact Analysis," presented at the AESP Spring Conference, Washington DC., May 2016.

19. "Caribbean Utility 2.0 Workshop- Economics, Tariffs and Implementation: The Challenge of Integrating Renewable Resources and After Engineering Solutions," co-hosted and presented at the Caribbean Renewable Energy Forum, Miami FL, October 2015.

20. "Dispelling Common Residential DR Myths," presented at the eSource Conference, October 2015.

21. "Low Income Customers and Time Varying Pricing: Issues, Concerns, and Opportunities," presented at NYU School Law's Forum on New York REV and the Role of Time Varying Pricing, March 2015.

22. "Dynamic Pricing: Transitioning from Experiments to Full Scale Deployments," presented at the EDF Demand Response Workshop, Paris, France; July 2014 and Governors Association's Michigan Retreat on Peak Shaving to Reduce Wasted Energy, August 2014.

23. "Impact Evaluation of TOU Rates when Experimentation is not Option: A Case Study of Ontario, Canada," presented at 2014 Smart Grid Virtual Summit, Boston, June 2014.

24. "Residential Demand Response Opportunities," presented at Opower Webinar Series, Boston, June 2014.

25. "Impact Evaluation of TOU Rates when Experimentation is not Option: A Case Study of Ontario, Canada," presented at 33rd Annual Eastern CRRI Conference, May 2014.

26. "The Arc of Price Responsiveness—Consistency of Results Across Time-Varying Pricing Studies," presented at the Chartwell Webinar, Boston, May 2013.

27. "Evaluation of Baltimore Gas and Electric Company's Smart Energy Pricing Program," presented at 9th International Industrial Organization Conference, Boston, MA, April 2011.

28. "Dynamic Pricing: What Have We Learned?" presented at the Electricity Markets Initiative Conference, Harrisburg, PA, April 2011.

29. "Do Smart Rates Short Change Customers," presented at the Demand Resource Coordinating Committee Webinar, December 2010.

30. "Opening Remarks and Session Chair of Day 1," at the FRA Conference on Customer Engagement in a Smart Grid World, San Francisco, CA, December 2010.

31. "The Impact of Informational Feedback on Energy Consumption," presented at the 2010 National Town Meeting on Demand Response and Smart Grid, June 2010.

32. "The Impact of In-Home Displays on Energy Consumption," presented before the Colorado Public Service Commission, June 2010.

33. "Does Dynamic Pricing Work in the Mid-Atlantic Region: Econometric Analysis of Experimental Data," presented at the Center for Research in Regulated Industries (CRRI) 29th Annual Eastern Conference, May 2010.

34. "Distributed Generation in a Smart Grid Environment," panel speaker at the Center for Research in Regulated Industries (CRRI) 29th Annual Eastern Conference, May 2010.

35. "Power of Information Feedback: A Survey of Experimental Evidence," presented at the Peak Load Management Alliance (PLMA) Webinar, April 2010.

36. "Customer Response to Dynamic Pricing - A Long Term Vision," presented at 2009 NASUCA Mid- Year Meeting, Boston, June 2009.

37. "BGE's Smart Energy Pricing Pilot Summer 2008 Impact Evaluation," presented at Association of Edison Illuminating Companies (AECI) Conference, Florida, May 2009

38. "California and Maryland - Are They Poles Apart?," presented at the Western Load Research Association Conference, Atlanta, March 2009.

39. "Experimental Design Considerations in Evaluating the Smart Grid," presented at the Smart Grid Information Session Massachusetts DPU, December, 2008.

40. "Divestiture, Vertical Integration, and Efficiency: An Exploratory Analysis of Electric Power Distribution," presented at the 4th International Industrial Organization Conference, Boston, Massachusetts, 2006.