Nova Scotia POWER
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PO Box 910 | Halifax, Nova Scotia | Canada | B3J 2W5

June 30, 2026

Crystal Henwood
Clerk of the Board
Nova Scotia Energy Board
1601 Lower Water Street, 3rd Floor
Halifax, NS B3J 3S3

Re: Time-Varying Pricing Pilot Program – Year Four (2024/25) Evaluation Report

Dear Ms. Henwood:

Nova Scotia Power Inc. (NS Power, Company) submits the Time-Varying Pricing (TVP) Pilot Year Four (2024/25) Evaluation Report (**Appendix A**). This Year Four Report presents the evaluated results for the 2024/25 Season (April 1, 2024 to March 31, 2025) and, in accordance with the Nova Scotia Energy Board (NSEB, Board) directive in M12499, includes an update on the status of outstanding directives and Consensus Agreement commitments (**Attachment 1**), as further detailed below.

Background

The TVP Pilot Program was developed by NS Power with the assistance of Brattle Group and stakeholder input in M09777. The Pilot, testing Time-of-Use (TOU) and Critical Peak Pricing (CPP) tariffs across the Domestic, Small General, and General rate classes, was approved by the Board on June 22, 2021.[1] The Multi-unit Residential Building (MURB) TOU Tariff was subsequently approved effective November 1, 2024, pursuant to the Board's Decision and Order in M11822.[2]

Following the finalization and approval of the Evaluation Measurement and Verification (EM&V) Plans in M09777, the Company has filed annual TVP evaluation reports with EM&V prepared by Econoler Inc.[3] As part of the 2023/24 TVP Application (M11822), and consistent

[1] M09777 – Board Decision, NS Power Time Varying Pricing Tariff Application, 284333, June 22, 2021.
[2] The Domestic, Small General, and General CPP and TOU Tariffs were initially approved in M09777 as a Pilot Program spanning November 1, 2021 to October 31, 2023. These six tariffs were extended for a third year effective November 1, 2023. On September 23, 2024, the Board approved the Company's proposed MURB TOU Tariff effective November 1, 2024 and extended the original six Tariffs for a fourth year (M11822).
[3] Prior evaluation reports filed with the Board: M10703 Interim Report (Year One, 2021/22) filed July 29,

with the 2024 Consensus Agreement, NS Power proposed that future evaluation reports be prepared internally by the Company and filed annually by August 31. In its September 23, 2024 Decision and Order, the Board accepted the terms of the Consensus Agreement with certain exceptions, including directing that the annual EM&V report be filed by July 31, 2025.[4]

Following the April 2025 cybersecurity incident, NS Power requested extensions to the filing deadline for the Year Four EM&V Report due to the temporary unavailability of AMI data and related systems.[5] By letter dated December 23, 2025, the NSEB provided:

> The Board approves NS Power's request to extend the filing date of the TVP 2024/25 (Year Four) EM&V report to June 30, 2026, or earlier if the Company is able to do so. The Board also approves the deferral of the outstanding Board directives and Consensus Agreement commitments to future Technical Sessions or the Year Four EM&V report. However, for greater certainty, NS Power is directed to report on the status of these directives and Consensus Agreement commitments when it files its Year Four EM&V report.[6]

An update on the status of these directives and commitments is provided in **Attachment 1** (2026/27 Work Plan).[7]

Summary of Year Four Evaluation Results

The Year 4 Report is the first EM&V conducted internally by NS Power. Overall, the findings indicate that the TVP Pilot continues to achieve peak load reductions in response to time-varying price signals. The evaluation results reflect continued growth in participation, with expanded enrolment in both residential and commercial customer classes in the 2024/25 Season. The results demonstrate sustained, statistically significant peak load reductions for Domestic TOU and CPP tariffs. Importantly, the Year Four evaluation identifies statistically significant load shifting for commercial TOU and CPP tariffs for the

2022; M11267 Year Two (2022/23) Report filed July 28, 2023, and M11823 Year Three (2023/24) Report filed July 31, 2024. This Year Four (2024/25) Report has been internally prepared by NS Power.

[4] M11822 – Board Decision and Order, 315765, page 2. September 23, 2024.

[5] On July 18, 2025, NS Power requested an extension to file the Year Four Report by November 1, 2025, due to the unavailability of Advanced Metering Infrastructure (AMI) data and supporting systems following the cyber incident. In its July 22, 2025 letter, the Board agreed to defer the filing and directed NS Power "provide more specifics about the filing of that annual report when the Company confirms its intent about the 2025/2026 TVP tariffs." Accordingly, in the October 1, 2025 Submission, the Company provided additional detail and committed to file an update on its progress by December 31, 2025, as subsequently directed by the Board. This progress update was provided in the Company's December 17, 2025 letter, which requested a further extension of the filing deadline to Q2 2026, or earlier if possible, and the deferral of outstanding directives and Consensus Agreement commitments to future Technical Sessions or the Year Four Report.

[6] M12499 – Board Letter, 326792, page 2. December 23, 2025.

[7] Attachment 1 provides an update on the status of directives and commitments that formerly formed the "2024/25 Areas of Focus Work Plan" – as last updated in M12499 (NS Power's October 1, 2025 Submission; Exhibit N-1) is as herein referred to as the "2026/27 Work Plan."

first time, representing a key advancement relative to prior evaluations, which did not find statistically significant results for commercial TVP tariffs.

The evaluation further examines customer response during periods of highest adjusted net load[8] and confirms that residential TVP participant load reductions continue to occur during these periods. For commercial participants, CPP is the only tariff demonstrating load reduction during the top 20, 50, and 88 highest adjusted net load hours.

The Year Four evaluated results are provided as **Appendix A**. NS Power engaged Econoler to provide advisory support and review of the evaluation methodology and results for Phase 4; Econoler's letter of review in **Attachment 2** confirms that NS Power's approach is consistent with prior phases and that the methodology updates are valid and sound. Customer research and feedback supporting the evaluation, including survey results prepared by Narrative Research, are provided in **Appendix B**. An overview of the marketing, education, and recruitment activities during the evaluation period is provided in **Appendix C**, and monthly participation levels by customer class are provided in **Appendix D**.

The Company has scheduled a technical session on July 14, 2026 to review the results of the Year Four Report with stakeholders. The Year 5 (2025/26) Report, to be filed by July 31, 2026, will include evaluated results for the MURB TOU Tariff only during the 2025/26 winter period – as other TVP tariffs were temporarily suspended for the entire 2025/26 Season, as described in M12499.

Stakeholder Engagement and 2026/27 Work Plan

During the 2024/25 TVP Season, NS Power undertook stakeholder engagement as part of its ongoing pricing innovation framework, consistent with the 2024 Consensus Agreement, including consultation on the evaluation and refinement of existing TVP tariffs, identification of future TVP opportunities, and consideration of potential program enhancements. These engagements also addressed directives arising from the Year Three Report (M11823) and other relevant proceedings, and commitments under the 2024 Consensus Agreement (M11822).

As outlined in M12499, engagement activities were temporarily paused following the cyber incident. Outstanding directives and Consensus Agreement commitments are addressed through the Year Four Report (**Appendix A, Attachment VII**), 2024/25 stakeholder engagement sessions, and future technical sessions, as summarized in **Attachment 1**. The Company has since resumed engagement and, on June 16, 2026, held a kick-off session with stakeholders which included an update on the 2026/27 Season – further detailed in the next section. Supporting materials from stakeholder sessions conducted during the 2024/25 Season are included as **Appendix E**.

[8] Adjusted Net Load refer to the hourly net system requirement, in MW, less all wind generation, in MW.

Update on the 2026/27 Season

As outlined in the Cybersecurity Incident Monthly Updates (M12273), NS Power expects all systems required for the administration of the TVP Tariffs to be restored in time for the 2026/27 TVP Season – beginning November 1, 2026.[9] TVP rates, as approved in the 2026-2027 General Rate Application (M12451), will resume once systems have been restored and the Pilot is able to return to normal operations, upon which no re-enrolment will be required for existing TVP participants. As system functionality becomes available, the Company will notify the Board and TVP participants at least 30 days prior to the start of the 2026/27 TVP Season, consistent with the Board's prior direction.[10]

Upon restoration of TVP administrative systems, the Company's objectives for the 2026/27 TVP Season are to:

- restore approved TVP rates to operational status effective November 1, 2026 with no modifications to the Pilot or tariff frameworks (i.e. status quo);
- refrain from active recruitment of new customers during the initial resumption period and maintain focus on a positive customer experience for existing participants;
- continue clear and proactive customer communications regarding the resumption of TVP tariffs to support customer confidence in the stability and integrity of the Pilot; and
- re-initiate and progress the work in relation to the prior directives and commitments (as outlined in **Attachment 1**) arising from prior stakeholder engagements and proceedings.

Conclusion

The Year Four Report (**Appendix A**) provides evaluated results for the 2024/25 Season, including sustained residential load shifting, statistically significant commercial load shifting, and initial results for the MURB TOU Tariff. Econoler's letter of review (**Attachment 2**) confirms that NS Power's approach is consistent with prior phases and that the methodology updates are valid and sound.

Consistent with prior years, this Report includes customer survey results prepared by Narrative Research (**Appendix B**), an overview of the marketing, education, and recruitment activities (**Appendix C**), and monthly participation levels by customer class (**Appendix D**). Materials from stakeholder sessions held during the 2024/25 Season are provided as **Appendix E**.

In accordance with the Board's direction, an update on the status of outstanding directives

[9] M12273 – Cybersecurity Incident Monthly Update 9, Attachment 2, page 1. June 12, 2026.
[10] Consistent with the Board Decision letter in M12499 directing that, for TOU, NS Power provide "15 days' notice to customers that on-peak and off-peak rates will resume if NS Power's systems are fully restored by February 15, 2026 (which would leave **about 30 days** remaining in the TVP winter period)" and, for CPP, that NS Power provide "**a 15-day grace period** given to customers for calling CPP events." [**emphasis added**]

and Consensus Agreement commitments is provided as **Attachment 1** to this correspondence. Items not addressed since the modification of the Pilot, for the 2025/26 Season, have been incorporated into the Year Four Report (**Appendix A, Attachment VII**), addressed in 2024/25 stakeholder engagements, or are planned to be advanced through future stakeholder engagement and technical sessions during the 2026/27 Season. A technical session to review the Year Four EM&V results is scheduled for July 14, 2026, at which stakeholders will be provided the opportunity to provide feedback and ask questions.

The Company will file the Year Five (2025/26) Report by July 31, 2026, which will include the second winter analysis for the MURB TOU Tariff.[11] Looking ahead, NS Power expects to resume TVP Pilot rates for the 2026/27 Season, consistent with the Board-approved tariff framework (M12451), and will notify the Board and participants at least 30 days' prior to the start of the Season (November 1, 2026) of the TVP Pilot resumption.

Yours truly,

Kathleen Murray

Kathleen Murray
Regulatory Counsel

[11] The Year Five Report will only include evaluated results for the MURB TOU Tariff, as other TVP tariffs were temporarily suspended during the 2025/26 Season.

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TIME-VARYING PRICING PILOT
2024/25 AREAS OF FOCUS WORK PLAN STATUS UPDATE – i.e. 2026/27 WORK PLAN

Summary of Deliverable / Commitment	Detail & Context	Source[1]	Initial Due by / Completed on	Status	Refer to
File proposed MURB TOU Tariff evaluation metrics	File, no later 31 December 2024, a list of the proposed MURB TOU Tariff evaluation metrics, and their definitions, along with an explanation of how it will measure the impact and difference in revenue received under this Tariff, compared to that which would have been received under the General tariff.	M11822 Directive	31 December 2024	complete	M11822 Compliance Letter filed December 17, 2024 + Appendix E, Attachment 1, page 31-34
Continue to refine MURB TOU Tariff to better reflect value of load shifting	This should be accomplished by considering marginal (or avoided) costs in determining the rates in each period.	M11822 Directive	Technical Session 1 (3 March 2025)	complete	Appendix E, Attachment 3, page 21
Work with stakeholders to refine methods of estimating load reductions	NS Power committed to try to refine its methodologies to estimate load reductions of heating groups if a viable method is identified. Further, NS Power is directed to work with stakeholders to refine its methods of estimating load reductions achieved through the TVP tariffs.	M11823 Directive	Technical Session 1 (3 March 2025)	complete	Appendix E, Attachment 3, page 22-24
Exploration of TVP revenue stability mechanisms	• TVP revenue stability will be explored using the structural and load shift revenue neutrality models and/or avoided cost models. • Provide an assessment of revenue impacts and potential tools available to address as required (e.g. enrolment targets, rate design scorecard).	2024 Consensus Agreement	Technical Session 1 (3 March 2025)	complete	Appendix E, Attachment 3, page 28-29 + Appendix E, Attachment 4, page 44-46

[1] "M11822 Directive" refers to the 2024/25 TVP Application proceeding, "M11823 Directive/Commitment" refers to the 2023/24 (Year Three) Evaluation Report proceeding, "2024 Consensus Agreement" refers to the 2024 TVP Consensus Agreement as filed in M11822, and "M11621 Directive" refers to the Smart Grid Nova Scotia Final Report proceeding.

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TIME-VARYING PRICING PILOT
2024/25 AREAS OF FOCUS WORK PLAN STATUS UPDATE – i.e. 2026/27 WORK PLAN

Summary of Deliverable / Commitment	Detail & Context	Source[1]	Initial Due by / Completed on	Status	Refer to
Review of accessibility as applicable to vulnerable customers (i.e. low-income)	• Examine the results of the Year 3 report as it relates to income and develop proposal to address gaps/opportunities, as appropriate • Assess potential impacts to vulnerable customers • Examination of challenges with more detailed income analyses (e.g. lack of control group) • In response to the Consumer Advocate's comments, NS Power will provide a summary of applicant characteristics (e.g. customer home type, primary heating source) for review and discussion re. barriers to accessing TVP Tariffs for renters v. homeowners	2024 Consensus Agreement	Technical Session 1 (3 March 2025)	complete	Appendix E, Attachment 3, page 6-12 + Appendix E, Attachment 4, page 36-37 and 41-43
Review of current metering and billing (Customer Information System) system capabilities	• Provide update on status of current metering and CIS system capabilities and future potential capabilities with system upgrade and plan to address in TVP strategy.	2024 Consensus Agreement	Technical Session 1 (3 March 2025)	complete	Appendix E, Attachment 3, page 26-27 + Appendix E, Attachment 4, page 37 and 45
Evaluate the extent to which the demand charge acts as a barrier	It is important that NS Power evaluate the extent to which the demand charge acts as a barrier to TOU participation for other commercial and industrial customers and continue to evaluate non-demand TVP rate designs for General Service customers.	M11822 Directive	Technical Session 2 (7 April 2025)	complete	Appendix E, Attachment 4, page 7-8
Assessment of demand charge impacts on General Service customers	Synapse believes that the demand charge is likely to be a barrier to TOU and CPP participation for other General Service customers beyond the MURB sector, and therefore it is imperative that NS Power evaluate demand charge modifications or alternatives for its TVP offerings to General Service customers.	M11822 Directive	Technical Session 2 (7 April 2025)	complete	Appendix E, Attachment 4, page 12

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2024/25 AREAS OF FOCUS WORK PLAN STATUS UPDATE – i.e. 2026/27 WORK PLAN

Summary of Deliverable / Commitment	Detail & Context	Source[1]	Initial Due by / Completed on	Status	Refer to
Evaluate the level of costs that are truly driven by an individual's non-coincident demands	Synapse recommends that NS Power evaluate the level of costs that are truly driven by an individual's non-coincident demands (e.g., an individual customer's transformer), and only recover those costs through a non-coincident demand charge. All other demand-related costs should be recovered through either an on-peak volumetric charge or a demand charge that only applies during on-peak hours.	M11822 Directive	Technical Session 2 (7 April 2025)	complete	Appendix E, Attachment 4, page 9-11
Undertake an analysis and model the changes in the demand charge for commercial customers shifting load from on-peak to off-peak	NS Power acknowledged that there may be a perceived risk of higher demand charges deterring commercial customers from participating in the TVP Pilot. NS Power agreed to undertake an analysis and model the changes in the demand charge for commercial customers shifting load from on-peak to off-peak.	M11823 Commitment	Technical Session 2 (7 April 2025)	complete	Appendix E, Attachment 4, page 8
Additional income-based billing impacts	Provided in response to Synapse's comments on Technical Session 1	Technical Session 1 Comments	Technical Session 2 (7 April 2025)	complete	Appendix E, Attachment 4, page 14-15 and 42-43
Small General and General CPP model results using 15 events + 3 hypothetical	Provided in response to Synapse's comments on Technical Session 1	Technical Session 1 Comments	Technical Session 2 (7 April 2025)	complete	Appendix E, Attachment 4, page 34-35 and 44-45
Assessment the degree to which the TVP offering reflect avoided costs	The Areas of Focus list for 2024/2025 includes a "review of system planning related values as applicable to TVP… including avoided costs." Synapse agrees with the review of avoided costs, but recommends that the discussion also include an assessment of the degree to which the TVP offering reflect avoided costs, with the potential for modifications to the tariffs to ensure that they are cost-reflective.	M11822 Directive	Future Technical Session – to be scheduled in 2026	planned	not applicable
Provide a draft weekend-inclusive TOU tariff to be reviewed by stakeholders in the upcoming engagement	• Examination of alternative Domestic tariffs including a TOU structure with weekend peak/off-peak periods	2024 Consensus Agreement	Future Technical Session – to be scheduled in 2026	planned	not applicable

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2024/25 AREAS OF FOCUS WORK PLAN STATUS UPDATE – i.e. 2026/27 WORK PLAN

Summary of Deliverable / Commitment	Detail & Context	Source[1]	Initial Due by / Completed on	Status	Refer to
sessions then file the EM&V metrics when NS Power is prepared to add the new tariff	• NS Power agreed with Synapse's recommendation to examine a weekend-inclusive TOU tariff. The Board directs NS Power to provide a draft weekend-inclusive TOU tariff to be reviewed by stakeholders in the upcoming engagement sessions. NS Power will incorporate appropriate feedback from the stakeholders into the proposed weekend-inclusive TOU tariff and provide the metrics for the tariff's evaluation to the Board when NS Power is prepared to add the new tariff to the TVP Pilot Program.	+ M11823 Directive			
Review of system planning related values as applicable to TVP	Review system planning related value applicable to TVP including: • Technologies that deliver load shifting • Update on the avoided cost analysis from 2023/24 (Year Three) Technical Sessions, how the avoided costs were applied to TVP, and rate design scorecard to discuss the assessment of TVP cost reflectivity • Examine alignment of TVP pricing with avoided cost and determine implications for future TVP pricing • Review of ELCC as applied to TVP	2024 Consensus Agreement	Future Technical Session – to be scheduled in 2026	planned	not applicable
Review potential structure for seasonally adjusted default rate	In response to Synapse's comments, in the TVP 2024/25 Kick-off Session in November 2024, on what a potential structure for a seasonally adjusted default rate might look like. NS Power will provide a reference rate with only a seasonal adjustment. NS Power does not intend to pursue such a rate other then as an informational tool on seasonal impacts for stakeholders.	November 2024 (Kick-off Session) Comments	Future Technical Session – to be scheduled in 2026	planned	not applicable
Discussion of new and/or revised tariffs enabling customers to have the option	• Review the opportunities and restrictions with batteries today on current TVP rates and general demand rates when	M11621 Directive	Future Technical Session – to be scheduled in 2026	planned	not applicable

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2024/25 AREAS OF FOCUS WORK PLAN STATUS UPDATE – i.e. 2026/27 WORK PLAN

Summary of Deliverable / Commitment	Detail & Context	Source[1]	Initial Due by / Completed on	Status	Refer to
to charge from, and discharge to, the grid with behind-the-meter energy storage (including vehicle-to-grid) that is not integrated with generation	paired with consumption and develop recommendations to address, as appropriate. • Identify and evaluate additional potential use cases of behind-the-meter energy storage in the context of TVP pricing ratios (e.g. 2:1, 10:1) and net metering.				
System peaking and TVP role	In response to the Energy Storage Canada comments, NS Power will: • Discuss why NS Power still views the winter evening peak to be the most likely and impactful time for a system peak moving forward. Variability in weather systems can affect timing of system peaks. This creates the potential for system peak to occur at other times such as the morning or weekend daily peaks. • What role TVP can play in meeting load and reserve requirements. Both though demand side flexibility, as well as by reducing variability in daily load.	Technical Session 1 Comments	Future Technical Session – to be scheduled in 2026	planned	not applicable
Demand-related costs v. demand-related revenues, by class	Provided in response to Synapse's comments on Technical Session 2	Technical Session 2 Comments	Future Technical Session – to be scheduled in 2026	planned	not applicable
Share the summary data for the segmentation model	Provided in response to the Consumer Advocate's and Synapse's comments on Technical Session 2	Technical Session 2 Comments	Response to 2025 Technical Session 2 comments	complete	Appendix E, Attachment 5, page 2
Where any standard load shapes exist for segments, please provide	Provided in response to SBA's comments on Technical Session 2	Technical Session 2 Comments	Response to 2025 Technical Session 2 comments	complete	Appendix E, Attachment 5, page 4-12

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TIME-VARYING PRICING PILOT
2024/25 AREAS OF FOCUS WORK PLAN STATUS UPDATE – i.e. 2026/27 WORK PLAN

Summary of Deliverable / Commitment	Detail & Context	Source[1]	Initial Due by / Completed on	Status	Refer to
Complete a performance assessment of the General Service Class customers then provide the outcomes first to stakeholders and then to the Board in the YR4 Report.	• The Year 3 Report notes that commercial customer enrollment in the TVP is low, making a robust evaluation of this customer group problematic. The Board directs NS Power to complete a performance assessment of the General Service Class customers, as described in Synapse's evidence, evaluating the extent that bills increase as they shift load from on-peak hours to off-peak hours. It is expected that this assessment will identify whether the demand charge increases the electricity bills for these participants. If the assessment finds that the demand charge results in higher bills to the commercial class customers shifting their load from on-peak to off-peak, NS Power is to assess removal of the demand charge, as well as any other changes, which could incentivize the participation of the commercial rate class customers in the TVP Program. • The Board directs NS Power to provide the outcome of this assessment and potential tariff changes to stakeholders during an engagement session and to the Board in the Year 4 Report. • The Board finds that if NS Power's assessment determines the demand charge is not a deterrent and/or the cause of lower commercial customer enrollment in the TVP, NS Power is directed to review and improve its customer engagement with commercial rate class customers and to revisit the incentive structure for the commercial TVP tariffs so that commercial operations and load shifting are not mutually exclusive.	M11823 Directive	Technical Session 2 (April 7, 2025)[2] + 2024/25 (Year 4) Evaluation Report	complete	Appendix E, Attachment 4, page 5-8 + Appendix A, Attachment VII

[2] In the September 2025 version of this Progress Update (filed as part of M12499) reported that this would be conducted in 2025 Technical Session 3 (with that date to be determined/postponed at the time); however, this was discussed and reviewed as part of the April 7, 2025 Technical Session 2.

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TIME-VARYING PRICING PILOT
2024/25 AREAS OF FOCUS WORK PLAN STATUS UPDATE – i.e. 2026/27 WORK PLAN

Summary of Deliverable / Commitment	Detail & Context	Source[1]	Initial Due by / Completed on	Status	Refer to
File YR4 Report	• Report on the Year Four findings no later than 31 Jul 2025 • File the annual Evaluation, Measurement and Verification (EM&V) report no later than 31 Jul 2025	M11822 Directive	2024/25 (Year 4) Evaluation Report	complete	Appendix A
Reporting back to stakeholders on changes that could be made to help customers determine whether they will benefit from TVP options	This report will be provided by NS Power and include the following: • Summary of the general load characteristics of small business customers that may enable a small business customer to shift load in response to TVP, CPP, or TOU rates. • Information on commercial/small business customer recruitment tele-marketing or on-site contact with the customer (including parent company staff), as may be necessary. NS Power does not currently collect complete SIC Code data for all customers. However, NS Power agrees that this type of information would be valuable and will explore analytical opportunities that could allow customers to be classified by business sector. NS Power will provide an update on these efforts in the report. • The recruitment tactics for contacting business customers for Years 4 and beyond have not yet been determined; however, should outcall be utilized, NS Power will provide the script.	2024 Consensus Agreement	Technical Session 2 (7 April 2025) + 2024/25 (Year 4) Evaluation Report	complete	Appendix E, Attachment 4, page 18-28 + Appendix E, Attachment 5, page 2-3 + Appendix A, Attachment VII
Provide an analysis of the correspondence of system margin forecasts and CPP events in the YR4 Report	NS Power agreed with Synapse that system margin forecasts may be a better indicator of when to call a CPP event. The Board directs NS Power to provide an analysis of the correspondence of system margin forecasts and CPP events in the Year 4 report, providing the days with a forecast of low system margin and the forecast system margin for the days when a CPP event was called.	M11823 Directive	2024/25 (Year 4) Evaluation Report	complete	Appendix A, Attachment VII

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TIME-VARYING PRICING PILOT
2024/25 AREAS OF FOCUS WORK PLAN STATUS UPDATE – i.e. 2026/27 WORK PLAN

Summary of Deliverable / Commitment	Detail & Context	Source[1]	Initial Due by / Completed on	Status	Refer to
Report on the review of marketing and communication efforts and its planned changes in the Year 4 Report	Synapse recommended NS Power analyze the differences in satisfaction among the tariffs and demographics and find improvements in communication with customers, particularly about bill savings. NS Power indicated that there will be a review of marketing and communication efforts with stakeholders through the pricing innovation process. The Board believes it is important that NS Power adequately communicate with the Pilot participants to set their bill savings expectations appropriately to ensure the Pilot can maintain enrollment, produce high-quality results and protect the trust of NS Power customers. NS Power is directed to report on the review of its marketing and communication efforts and its planned changes, informed by stakeholders through the pricing innovation process, in the Year 4 Report.	M11823 Directive	2024/25 (Year 4) Evaluation Report	complete	Appendix A, Attachment VII + Appendix C + Appendix E, Attachment 3, page 32-43 and 48-60 + Appendix E, Attachment 4, page 38-41 and 46-47
Develop and provide an analysis of commercial class customer characteristics that have the capacity in the TVP to reduce load at peak periods	• Following the completion of the Year 4 pilot, NS Power will develop and provide to stakeholders an examination of the commercial class customer characteristics (load shape, magnitude, business type) that have demonstrated the capacity in the TVP pilot to reduce load during peak periods. Findings may enable targeted outreach to non-TVP pilot small business customers with similar characteristics, with the intent to improve enrolment and response to CPP and/or TOU peak periods • NS Power agreed with Synapse's recommendation to improve customer education and to continue collecting participant feedback. As part of the 2024/25 Areas of Focus, NS Power will develop and provide stakeholders with an analysis of commercial class customer characteristics that have the capacity in the TVP to reduce load at peak periods.	2024 Consensus Agreement + M11823 Commitment	2024/25 (Year 4) Evaluation Report	complete	Appendix A, Attachment VII + Appendix E, Attachment 4, page 18-28 + Appendix E, Attachment 5, page 2-3

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2024/25 AREAS OF FOCUS WORK PLAN STATUS UPDATE – i.e. 2026/27 WORK PLAN

Summary of Deliverable / Commitment	Detail & Context	Source[1]	Initial Due by / Completed on	Status	Refer to
Continue to file annual Evaluation Reports	• Maintain the established TVP Report and EM&V processes • File an annual EM&V report that will be prepared internally by NS Power	2024 Consensus Agreement	2024/25 (Year 4) Evaluation Report	complete	Appendix A
Conduct a MURB Industry Group Session	Session may include a discussion on the following: • Based on feedback received from MURB stakeholders, the parties acknowledge that incentives and rebates from third parties are expected to be required to support the adoption of TVP rates by MURB customers and the parties will support the development and introduction of such opportunities	2024 Consensus Agreement	To be scheduled in 2026	planned	not applicable

To: Nova Scotia Energy Board

BY EMAIL June 25, 2026

To: Nova Scotia Energy Board

From: Econoler, Evaluation Consultant

Subject: Econoler's Review of Nova Scotia Power's Time-Varying Pricing Pilot Program Phase 4 Evaluation

Context

This memo summarizes the support provided by Econoler to Nova Scotia Power (NS Power) in the finalization of Time-Varying Pricing (TVP) Pilot Program Phase 4 Evaluation. Econoler was contracted by NS Power to provide advisory support and review the methodological changes implemented by NS Power for the impact evaluation of TVP Phase 4.

Econoler holds extensive experience in impact evaluation of energy programs, being the leading provider of demand side management (DSM) program evaluation services to Canadian utilities, energy efficiency agencies, and grid operators. Econoler conducted the impact evaluation for Phases 1, 2 and 3 of the TVP pilot.

Econoler's involvement for the TVP Phase 4 evaluation report included:

- Providing details to NS Power on the methodology applied by Econoler for the evaluations of TVP Phase 1 to Phase 3, to ensure NS Power had a full understanding of the approach previously used.
  - This knowledge transfer included documentation sharing and meetings between the Econoler and NS Power teams.
- Review of the methodological changes proposed by NS Power, namely the use of mixed-effect models to measure impacts for commercial TVP customers, as well as for residential TVP customers who were also participants in EfficiencyOne's Eco Shift demand response program. NS Power also implemented the use of robust margins of error for results calculated with mixed effects models.
  - The review conducted by Econoler included meetings in which NS Power presented the proposed methodology changes, along with benefits of these changes, as well as a full review of the draft version of the evaluation report (including appendices).
  - Following the review of the report, Econoler submitted comments and clarifying questions to NS Power, all of which were subsequently addressed by NS Power.
  - The review conducted by Econoler did not include calculation files.

Conclusion of the Review

Econoler provided guidance and clarifications to NS Power to ensure a consistent and appropriate application of the overall evaluation methodology established for TVP Phase 1 to 3. Additionally, based on the discussions with the NS Power team and on the review of the draft report, Econoler found that the methodological changes were valid, and that the justifications provided by NS Power in the report for these changes were sound.

Time-Varying Pricing Pilot Program Phase 4

Evaluation, Measurement & Verification Report

June 30, 2026

Nova Scotia POWER
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Abbreviations

AMI	Advanced Metering Infrastructure
ANL	Adjusted Net Load
CPP	Critical Peak Pricing
DD	Difference-in-difference
DDD	Triple difference-in-differences (Eco Shift)
DOM	Domestic Rate Class
DR	Demand Response
EM&V	Evaluation Measurement & Verification
E1	EfficiencyOne
EV	Electric Vehicle
HDD	Heating Degree Days
HRM	Halifax Regional Municipality
kW	Kilowatt
kWh	Kilowatt hour
MAE	Mean Absolute Error
MBE	Mean Bias Error
MoE	Margin of Error
MURB	Multi-unit Residential Building
NHW	Non-Holiday Weekday
NS Power	Nova Scotia Power
NSEB	Nova Scotia Energy Board
RMSE	Root Mean Square Error
SLR	Seasonal Load Ratio
SOR	Standard Offer Rate
TOU	Time-of-Use
TVP	Time-Varying Pricing

Definitions

Adjusted Net Load	The hourly net system requirement (MW) less all wind generation (MW)
Cohorts	Cohorts are numbered based on the Phase they enrolled in the TVP program. For example, Cohort 4 refers to participants recruited in Phase 4 (i.e. the fourth Winter), which started November 2024.
Commercial	Customers on the Small General and General rate class are referred to as Commercial; this applies to methodology and results. Unless specified as Small General or General, Commercial indicates both rate classes.
Consumption / Usage	Describes electricity consumption in terms of energy (kWh).
Control	Customers who did not participate in the pilot and had met the control group selection criteria requirements with the highest similarity to their treatment counterpart.
Demand	Describes the maximum 15-minute electricity consumption in terms of power (kW) calculated at AMI interval data frequency (i.e. every 15 minutes).
Income	Income definitions are aligned with provincial income tax brackets.[1] Low - (Annual Income ≤ $61,000) Medium - ($61,000<Annual Income ≤ $96,000) High – (Annual Income > $96,000)
Load	Describes the average hourly electricity consumption in terms of power (kW).
Peak	The highest rate paid by TVP participants. For Time of Use (TOU), the term "peak periods" refers to the time during which the peak rate is in effect for the TOU Tariff. For Critical Peak Pricing (CPP), the term "peak events" refers to the time during which the peak rate is in effect.
Phase	The evaluation of Phase 1 of the TVP pilot was conducted with participants who signed up for the first Winter of the pilot and included data between November 2021 and March 2022. Phase 2 includes Cohort 1 and Cohort 2 participants and covers data available between April 2022 and March 2023. This year's evaluation, Phase 4, includes Cohort 1, Cohort 2, Cohort 3 and Cohort 4 participants and covers data available between April 2024 and March 2025.
Pilot period	For this report (Phase 4) this is April 2024 – March 2025.
Pre-pilot	The year before the TVP Tariff took effect for the Cohort. This period is November 2020 to October 2021 for Cohort 1 participants, November 2021

[1] Government of Nova Scotia. (n.d.). *Personal income tax rates and indexation*. Retrieved June 10, 2026, from https://www.novascotia.ca/personal-income-tax-rates-and-indexation

	to October 2022 for Cohort 2 participants, November 2022 to October 2023 for Cohort 3 participants and November 2023 to October 2024 for Cohort 4 participants.
Residential	Customers in the Domestic rate class are referred to as Residential; this applies to methodology and results.
Snapback	Defined as load increases during the four-hour period following a Time-of-Use peak period or a Critical Peak Event. The duration of the snapback is proportional to the peak period or event duration. For example: A peak period from 5 – 9 PM has a Snapback period from 9 PM – 1 AM.
Standard Offer Rate	The default rate applicable to a customer for their specific rate class. For example, residential customers by default would be on the Domestic Tariff.
Treatment	A participant in the TVP pilot rates (i.e. TOU, CPP, MURB TOU)
Winter / Non-Winter	Winter: November through March, inclusive Non-Winter: April through October, inclusive. Historically referred to "Summer" in previous TVP EM&V reports.

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Executive Summary

Nova Scotia Power (NS Power, Company) launched the Time-Varying Pricing (TVP) Tariff Pilot on November 1, 2021, with the purpose of encouraging customers to shift load from Winter peak periods to Winter off-peak periods. These tariffs present customers with the option to lower their energy bills if they participate in load shifting. Shifts in load away from peak periods avoids generation, transmission, and distribution capacity investments. Load shifted away from peak periods also creates system savings in the near-term in the form of reduced fuel, purchased power costs, and carbon emissions.

This report marks the fourth annual TVP Report (i.e. Phase 4, April 1, 2024 to March 31, 2025), as such the load and economic impact evaluation pertains to this period. All cohorts are named according to the Phase of the evaluation in which they joined (i.e. Cohort 2 customers joined the pilot during Phase 2).

Since the first report, modifications to the evaluation metrics and the rates themselves have been made with the support of expert consultants and stakeholders. These modifications have refined the evaluation to provide accurate load and billing effects from customers participating in TVP, while creating rates that achieve demand response (DR) targets in a cost-optimized manner. One of these modifications included the transfer of TVP evaluation measurement and verification (EM&V) from consultants to NS Power, Phase 4 marks the first evaluation performed by NS Power.

Residential Time-of-Use (TOU) and Critical Peak Pricing (CPP) participants have expanded their enrolment by a combined 5,148 customers since Phase 3 – this represents an increase of approximately 160%. These Domestic Tariffs continue to demonstrate on-peak load reduction effect per customer similar to previous Phases (TOU = 0.16 kW or 7.6%, CPP = 0.69 kW or 27%). These effects are similar during periods of low wind and high system load (i.e. highest adjusted net load (ANL) hours).

Since Phase 3, Commercial TOU and CPP participants have expanded their enrolment by a combined 43 customers – an increase of approximately 66%. This increase in sample size combined with improved regression methodologies has, for the first time, demonstrated statistically significant on-peak load reduction effect per customer (TOU = 0.80 kW or 7.5%, CPP = 6.3 kW or 9.6%). For CPP, these effects are not observed consistently across all event calls but are observed during the highest ANL hours, whereas for TOU the effect during top ANL hours is statistically insignificant.

For the first time, the ten customers on the Multi-unit Residential Building (MURB) TOU Tariff were evaluated. Results indicate a small, but statistically significant, load shift during evening peak periods (0.54 kW, approximately 2.1%). During the morning period and during the highest ANL hours, MURB TOU customers indicate potential load reductions; however, these results are statistically insignificant. Notably, no change in monthly demand was observed in MURB TOU participants, despite the removal of the demand charge.

As the TVP Pilot evolves and scales, this report not only serves as a diagnostic tool for program evaluation, but it also aids in determining the next steps for TVP DR in Nova Scotia.

Tariffs

Both TOU and CPP are available in the Domestic, Small General, and General rate classes, whereas MURB TOU is available to MURBs in the General rate class. A summary of the TVP Tariffs is provided in Attachment I: Riders and Tariff Structure.

Domestic, Small General, and General TOU has two four-hour peak periods occurring on all non-holiday weekdays, 7–11 AM and 5–9 PM, November through March (Winter); all other hours during the Winter period are considered off-peak. During Winter off-peak periods, customers are charged the same as the standard offer rate (SOR), while during on-peak periods, customers are charged twice the off-peak rate. From April to October (non-Winter), the rate is approximately 30% lower relative to the SOR for the entire season.

MURB TOU has two four-hour peak periods (7–11 AM, 5–9 PM) with a mid-peak (11 AM–5 PM) occurring seven days per week during the Winter season. During non-Winter there is one peak period per day (7 AM – 9PM) with all other hours as off-peak. Unlike the other TOU rates, holidays and non-holidays have the same rate structure. Unlike the General SOR, the MURB TOU Tariff does not have a demand charge. The mid-peak Winter rate is equal to the SOR first energy block.[2] During Winter, the on-peak rate is twice that of the SOR rate and the off-peak is approximately 15% lower relative to the SOR rate. During non-Winter, the on-peak and off-peak rates are 5% and 20% lower, respectively, as compared to the SOR first energy block.

CPP has up to 18 four-hour events per Winter season. Events are scheduled by the System Operator based on the day-ahead system load forecast and dispatch schedule. Customers must be notified by 4 PM the day before the event. Customers are reminded within one hour of the event starting and once it is completed. Events can be called up to three times per week (Monday through Sunday), at any time between 6 AM and 11 PM, and may include up to three weekend events per TVP Season. Peak pricing for CPP is 10 times the SOR price, and off-peak pricing is approximately 16% lower than the SOR rate for each rate class.

Residential Findings

In total, 5,616 TOU and 2,642 CPP residential customers participated in the TVP program in Phase 4. Of these, 4,938 TOU and 2,310 CPP customers were included in the regression when counting only those who meet the criteria defined by the methodology; as described in . Consistent with Phase 3, TVP Pilot participants continued to achieve significant electricity load reductions during peak periods (for TOU) and events (for CPP), as summarized in Table 1.

Table 1: Summary of Peak Load Reductions by Residential TVP Tariff

TVP Tariff	Absolute Load Reduction (kW)		Relative Load Reduction (%)	
	Morning Peak	Evening Peak	Morning Peak	Evening Peak
Residential TOU	0.15 kW	0.17 kW	7.4%	7.9%
Residential CPP	0.61 kW	0.77 kW	24.6%	28.5%
Statistical Significance	✓	✓	✓	✓

[2] The General SOR Energy Charge has two blocks: one for the first 200 kWh per month per kW of maximum demand and a lower rate for all additional kWh.

Residential TOU participants reduced load during peak periods (0.16 kW / 7.6%) with minimal snapback (0.014 kW during evenings only) while also reducing overall annual energy (300 kWh per year), resulting in an average annual electricity bill reduction ($110 / 5.5%). This average load reduction during peak hours in Phase 4 is consistent with that observed in Phase 3 (0.15 kW). Significant enhancements to load reduction (+0.40 kW) occurred where technology (i.e. Eco Shift + smart device) were present. Notably, load impact during the highest 88 ANL hours were consistent with average peak periods (0.17 kW). All heating classifications demonstrated load reduction; however, those with steady electric space heating achieved the highest average load reduction of 0.19 kW during peak hours, whereas participants with steady non-electric space heating systems experienced the lowest load reduction of approximately 0.08 kW. Participants who electrified their space heating with TOU provided a compelling case for electrification by achieving statistically significant load reduction (0.11 kW) during peak periods with no statistically significant change in overall annual energy consumption (27.7 ± 37 kWh per year) while still saving on their annual electricity bill ($153 per year) in addition to any fuel savings from non-electric heating sources they may have reduced.

Residential CPP participants reduced load during peak periods (0.69 kW / 27%) with a statistically significant overall snapback (0.060 kW). Participants reduced overall annual energy (355 kWh per year), resulting in an average annual electricity bill reduction ($208 / 8.6%). This average load reduction during peak hours in Phase 4 (0.61 ± 0.03 kW morning / 0.77 ± 0.03 kW evening) is less than that observed in Phase 3 (0.768 ± 0.222 morning / 0.943 ± 0.439 kW evening); however, the differences are within the margin of error. Significant enhancements to load reduction (0.46 kW) occurred where technology (i.e. Eco Shift + smart devices) were present. Notably, load impact during the highest 88 ANL hours that coincided with CPP events (0.80 kW) were higher than during average peak periods. All heating classifications demonstrated load reduction; however, those with steady electric space heating achieved the highest average load reduction of 0.83 kW during peak hours, whereas participants with steady non-electric space heating systems experienced the lowest load reduction of approximately 0.24 kW. Participants who electrified their space heating with CPP provided a compelling case for electrification due to achieving statistically significant load reduction (0.75 kW) during peak periods with marginal overall annual energy increase (945 ± 211 kWh per year). Although electrified participants did not experience statistically significant change (i.e. increase or decrease) in electricity bill, it does not account for any additional fuel savings from non-electric heating sources they may have reduced.

Commercial Findings

The commercial TVP Tariffs attracted more businesses, with Phase 4 enrolment (108 businesses) higher compared to Phase 3 (65 businesses). While "small sample size and the wide variety of energy consumption profiles prevented obtaining conclusive impact evaluation results"[3] in Phase 3, the larger sample and improved regression analysis in Phase 4 enable a more robust assessment of the load and economic impacts of TVP commercial tariffs. Commercial TVP pilot participants achieved significant electricity load reductions during peak periods (for TOU) and events (for CPP) in Phase 4 (Table 2).

[3] M11823 – TVP Pilot Program — 2023/24 (Year Three) Evaluation Report, Appendix A, page 51. July 31, 2024.

Table 2: Summary of Load Reductions by Commercial TVP Tariff

TVP Tariff	Absolute Load Reduction (kW)		Relative Load Reduction (%)	
	Morning Peak	Evening Peak	Morning Peak	Evening Peak
Commercial TOU	0.7 kW	0.9 kW	6.4%	8.6%
Commercial CPP	7.9 kW	5.1 kW	11.4%	7.9%
Statistical Significance	✓	✓	✓	✓

Commercial TOU Participants reduced load during peak periods (0.80 kW / 7.5%) with a statistically significant evening snapback (0.90 kW). However, the overall snapback effect of 0.11 kW for TOU participants was not statistically significant due to a load reduction during the morning snapback period (0.51 kW). Notably, largest overall reductions occurred during the evening peak period in February 2025, when the average outdoor temperature was on average −3 °C. Overall, commercial TOU participants experienced an increase in daily electricity usage of 15.4 kWh/day. When separated by rate class, Small General customers exhibit a load increase during peak periods (0.22 kW) relative to the General rate class that demonstrate a load reduction (2.6 kW). These results suggest that commercial TOU participants under General Tariff are more responsive to price signals, while those under Small General Tariff show counterproductive responses. During the highest ANL hours that coincide with TOU peak periods, participants did not exhibit statistically significant load reduction.

Commercial CPP Participants reduced load during peak periods (6.3 kW / 9.6%) with a statistically insignificant overall snapback. Notably, the CPP participants exhibited a statistically significant snapback effect (6.9 kW) on days when both morning and evening CPP events occurred. The CPP participants achieved the largest overall reductions during the evening event in December 2024, when the average outdoor temperature was on average −8 °C. Overall, commercial CPP participants experienced a significant reduction in daily electricity usage of 65 kWh/day during CPP event days. When separated by rate class, Small General customers exhibit no statistically significant changes in load during peak periods compared to the General rate class that demonstrate a load reduction (9.7 kW). These results suggest that commercial CPP participants under General Tariff are more responsive to price signals, while those under Small General Tariff show statistically insignificant responses. During the highest ANL hours that coincide with CPP peak periods, participants achieved higher-than average load reductions.

MURB TOU Findings

Phase 4 marks the first load and economic impacts evaluation of the MURB TOU Pilot Tariff. Ten MURBs were recruited and are enrolled in the MURB TOU Tariff. For the MURB TOU Tariff, this Phase 4 evaluation includes the Winter period from November 2024 to March 2025.

MURB TOU participants achieved an overall load reduction of approximately 0.48 kW during peak periods; however, only the reduction during evening peak hours was statistically significant (Table 3). MURB TOU participants demonstrated overall load reductions during the Winter period, except in March, when they exhibited a significant increase in load.

Executive Summary

Table 3: Summary of Load Reductions from MURB TOU Tariff

TVP Tariff	Absolute Load Reduction (kW)		Relative Load Reduction (%)	
	Morning Peak	Evening Peak	Morning Peak	Evening Peak
MURB TOU	0.44 kW	0.54 kW	1.8%	2.1%
Statistical Significance	X	✓	X	✓
Note: Throughout this report, statistically significant results will be displayed in tables with black font, whereas statistically insignificant results will be displayed in grey font.				

MURB TOU participants demonstrated an overall negative snapback effect (0.92 kW), indicating reduced electricity use during snapback periods. On average, participants reduced load by 1.2 kW during the morning snapback period and no statistically significant snapback during the evening snapback period. MURB TOU participants demonstrated mixed results across the highest ANL hours. These reductions were not statistically different from the average load reductions observed during ANL hours that coincided with TOU peak periods. Statistically significant reductions were only observed during the top 50 and top 88 highest ANL hours.

Unlike other tariffs in the General rate class, the MURB TOU Tariff offers an electricity rate without a demand charge. To understand the demand impact, the effect MURB TOU Tariff on demand was evaluated. Findings revealed that MURB TOU participants saw no statistically significant changes in monthly demand, although statistically significant 15-minute demand decrease occurred during morning snapback period and pre-evening snapback periods it did not impact monthly demand. Additionally, MURB TOU participants demonstrated statistically insignificant changes in daily electricity usage during the Winter overall and during individual Winter months. Notably, many of the findings from MURB TOU impact analysis are not conclusive due to the small sample size.

Introduction

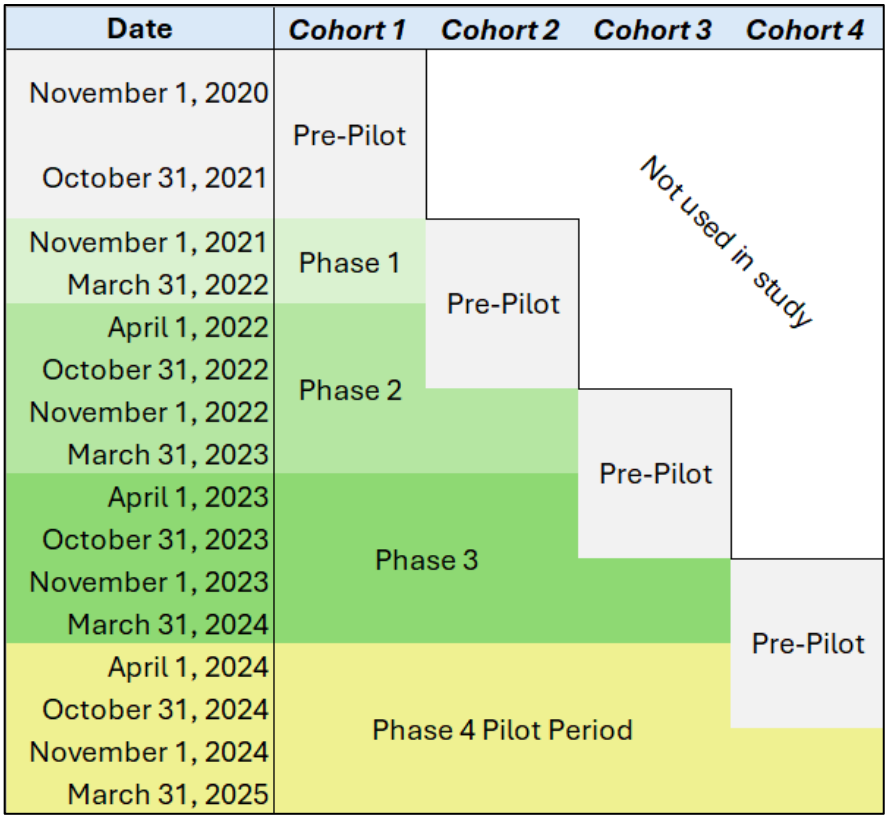
Time-Varying Pricing (TVP) is a scalable customer-focused demand response (DR) program. In Nova Scotia, the TVP pilot has grown significantly since it began in November 2021. Since its inception, the TVP pilot has offered two tariffs, Time-of-Use (TOU) and Critical Peak Pricing (CPP), within three separate rate classes (Domestic, Small General and General). The objective of these rates is to provide customers with rate choice that can enable them to save on their electricity bill while shifting demand from peak periods. By promoting load shifting, the program aims to reduce, in the near term, fuel and purchased power costs, and over the longer-term reduce costs in the form of avoided generation, transmission, and distribution infrastructure capital costs.

This report and its analytical process serve as a method for quantifying the load and billing impacts from TVP. Through stakeholder collaboration, the evaluation methods, the rates, and the TVP Tariff constructs have been modified iteratively. New in Phase 4 is the multi-unit residential building (MURB) TOU Pilot Tariff, which was launched on November 1, 2024. This is the first new Tariff since the inception of the TVP pilot program. This Tariff, along with the six originals, are evaluated as part of this year's Evaluation, Measurement, and Verification (EM&V) report (i.e. TVP Phase 4 EM&V).

Evaluation Scope

This evaluation pilot period (i.e. Phase 4) analyzes advanced metering infrastructure (AMI) data from November 1, 2020 – March 31, 2025. Each Phase, the pilot period shifts by 1-year; however, the pre-pilot period remains static for each cohort, as illustrated in Figure 1.

Figure 1: Phase 4 Experimental Design Timeline



The first year a cohort enters the TVP pilot (e.g. Cohort 2 in Phase 2), the evaluation for this cohort was limited to the Winter period (i.e. November to March). Subsequent evaluations for all cohorts include a full year (i.e. April to March).

Evaluation metrics are separated into two impact categories, "Load & Usage" and "Economic". Refer to Table 4 for a summary of each metric included in the Phase 4 report.

Table 4: Impact Evaluation Metric Summary

Category	Metric	TOU, CPP, MURB TOU (all rate classes unless specified)
Load & Usage Impact	**Change in load during peak periods (kW)**	• Change in load (kW) during peak, and overall impact during Winter and non-Winter. Mid-peak hours included for MURB TOU. • Change in load during peak by region (Halifax area vs. rest of Nova Scotia). • Change in load by month (TOU rates only). • Change in load by space heating classification (Residential rates only). • Additional change in load from Eco Shift program (Residential rates only). • Change in load by income classification (Residential rates only).
	Snapback (kW)	• Change in hourly average load (kW) over 4 hours immediately after peak hours.
	Change in load during highest ANL hours (kW)	• Change in load during the highest adjusted net load (ANL) hours based on the highest 20, 50, and 88 ANL hours during the year, including analysis of coincident tariff peak and highest ANL hours.
	Change in average usage levels (kWh)	• Change in the average daily usage levels (kWh/day) and relative change in daily electricity usage (%) during Winter and non-Winter.
	Change in Demand (kW), MURB TOU only	• Change in maximum 15-minute load with respect to peak periods, pre-peak and post-peak (i.e. Snapback Period). • Change in maximum 15-minute load with respect to month.
Economic Impact	**Change in electricity bills**	• Change in daily electricity bill ($) during Winter, non-Winter, and annual average.
	Price Elasticity	• Daily and inter-period substitution price elasticity (percent (%) change in load per one percent (%) change in price).

Participation

The TVP pilot program has increased enrolment year over year with a total of 8,376 participants at the end of Phase 4. Refer to Table 5 and Table 6 for participation summaries.

Table 5: TVP Participation on March 31 by Phase and Tariff

Phase	DOM TOU	SMG TOU	GEN TOU	DOM CPP	SMG CPP	GEN CPP	MURB TOU	Total
Phase 1	676	24		284	8		0	**992**
Phase 2	891	17		373	2		0	**1,283**
Phase 3	2,241	37	19	922	3	6	0	**3,228**
Phase 4	5,616	37	18	2,642	17	36	10	**8,376**

The average customer retention rate per TVP Tariff ranges from 87% (Domestic TOU) to 100% (MURB TOU), refer to Table 6 for additional details.

Table 6: Participation Summary and Retention Results

TVP Tariff	**A** Enrolled prior to beginning of Phase 4 Winter (October 31, 2024)	**B** Enrolled during Phase 4 Winter (November 1, 2024 to March 31, 2025)	**C** Withdrew mid Phase 4 Winter (November 1, 2024 to March 31, 2025)	**D** Remained enrolled at end of Phase 4 Winter (March 31, 2025)	$1-\left(\frac{C}{A+B}\right)$ Percentage of Enrolled Participants Who Completed Phase 4
Domestic TOU	2,174	4,271	829	5,616	87%
Domestic CPP	885	2,023	266	2,642	91%
Small General TOU	36	5	4	37	90%
Small General CPP	3	16	2	17	89%
General CPP	19	0	1	18	95%
General TOU	6	32	2	36	95%
MURB TOU	10	0	0	10	100%

1 Methodology

The methodology is primarily composed of two components: control group selection and regression modelling.

Control group selection includes matching treatment customers with control customers based on a similar location (i.e. neighbourhood), space heating type (e.g. electrified), participation in EfficiencyOne's (E1) Eco Shift program, while balancing for effects from other E1 programs such as Green Heat, Home Energy Assessment, and Efficient Product Installation. While considering these non-load metrics, each treatment customer is matched to a control customer with the most similar average and peak load profiles during the pre-pilot period by means of a 'Similarity Metric,' which is defined by a Euclidean distance calculation.

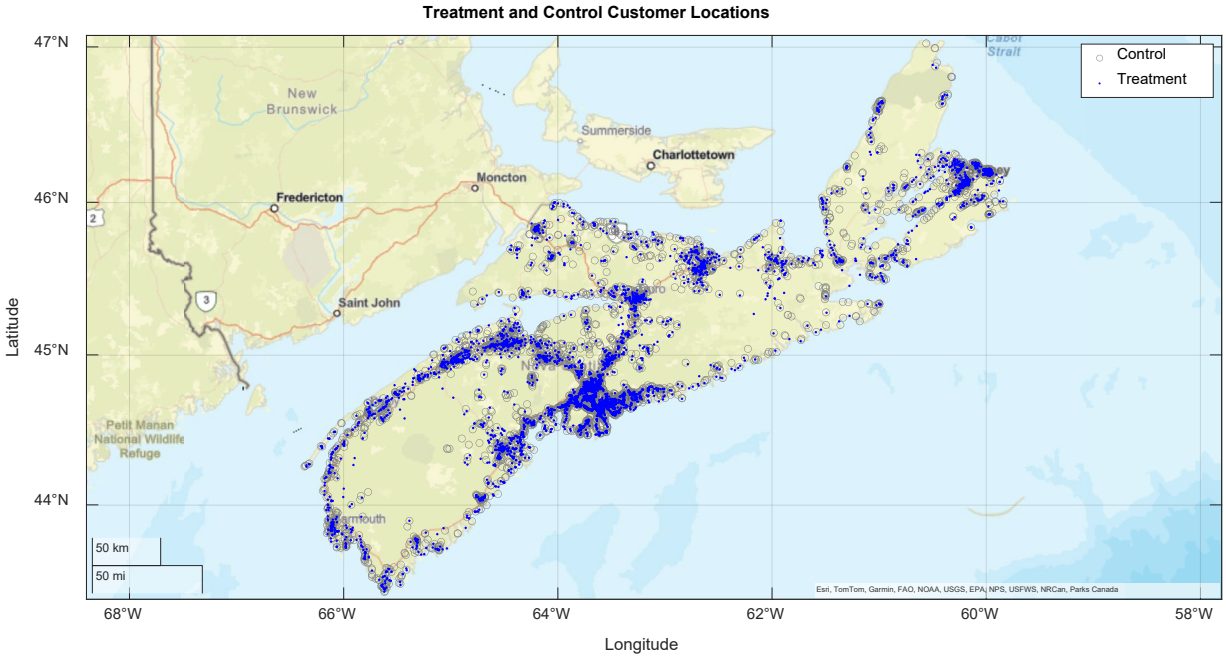
The regression models in this EM&V use both a fixed and mixed-effects regression model that primarily relies on a difference-in-difference (DiD) model, and where necessary, a triple difference (DDD) model is utilized. Generally, the regression model includes variables to account for which customers are control and treatment, TVP price signals, and temperature using heating degree days (HDD). For commercial TOU and CPP tariffs, a semi-difference-in-differences (semi-DiD) approach is used due to not establishing a viable control group.

For additional details regarding the methodology and equations used, refer to Attachment III: Methodology. For how these methodologies have progressed since the start of TVP at Nova Scotia Power, refer to Attachment IV: Historical Methodological Changes.

2 Control Group Selection

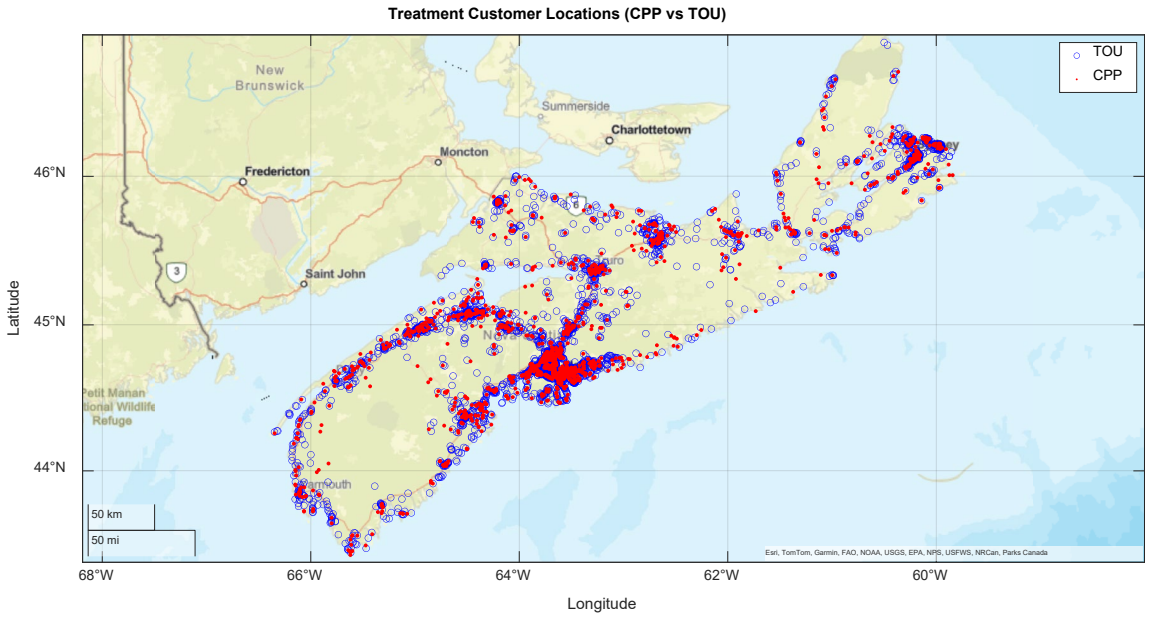
The control group selection methodology uses 1-hour average and 15-minute peak load data to determine the best 1:1 control match by four neighbourhoods. If treatment customers are distributed throughout the province proportional to the population, control customers should follow a similar distribution. To confirm this assumption, a geographic visual of Nova Scotia demonstrates both Treatment and Control customers are distributed similarly to each other; refer to Figure 2.

Figure 2: Geographic Distribution of Treatment and Control Customers from all Rate Classes



Although it is not a pre-requisite that CPP and TOU customers be similarly distributed throughout Nova Scotia, it is a benefit which ensures comparison between the two programs are not skewed due to any potential geographic differences. The distribution of both TOU and CPP treatment customers is presented in Figure 3.

Figure 3: Geographic Distribution of TOU and CPP Treatment Customers (All Rate Classes)



As shown in Figure 2 and Figure 3, the distribution of Treatment and Control groups for both TOU and CPP customers is observably distributed in alignment with the Nova Scotia population.

2.1 Residential TOU & CPP

To best evaluate load and billing effects of the TVP pilot, it is important to have a control group with similar load characteristics to that of the treatment group. The control group selection load profile match is presented for TOU and CPP in Figure 4 and Figure 5, respectively, with results indicating greater than a 96% match accuracy for both average and maximum loads as defined by the methodology in equation (4).

Figure 4: Residential TOU Pre-Pilot Control & Treatment Load Profile Comparison

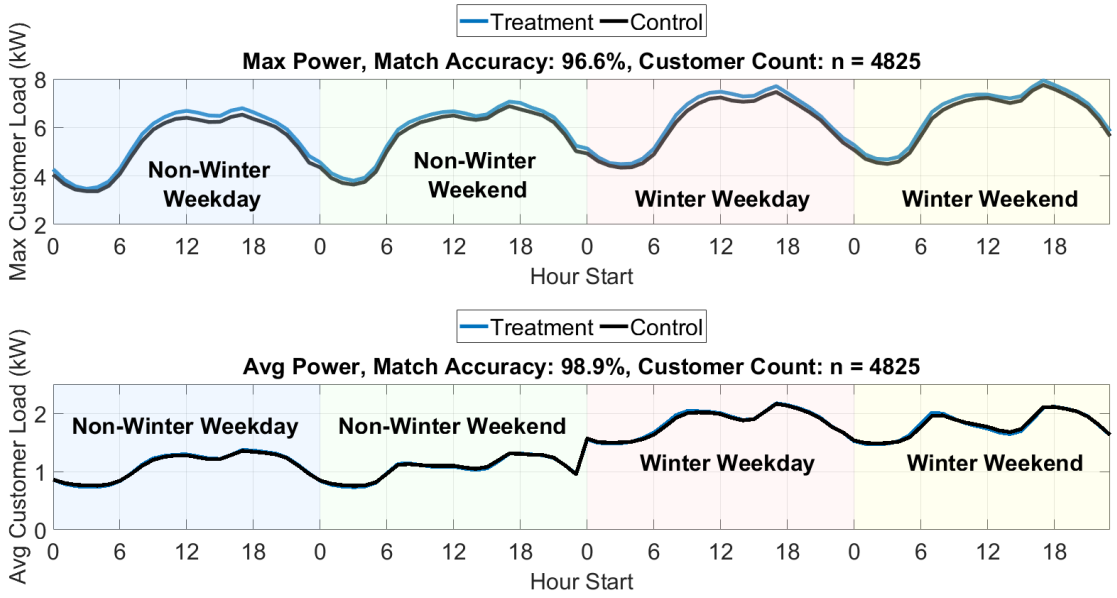
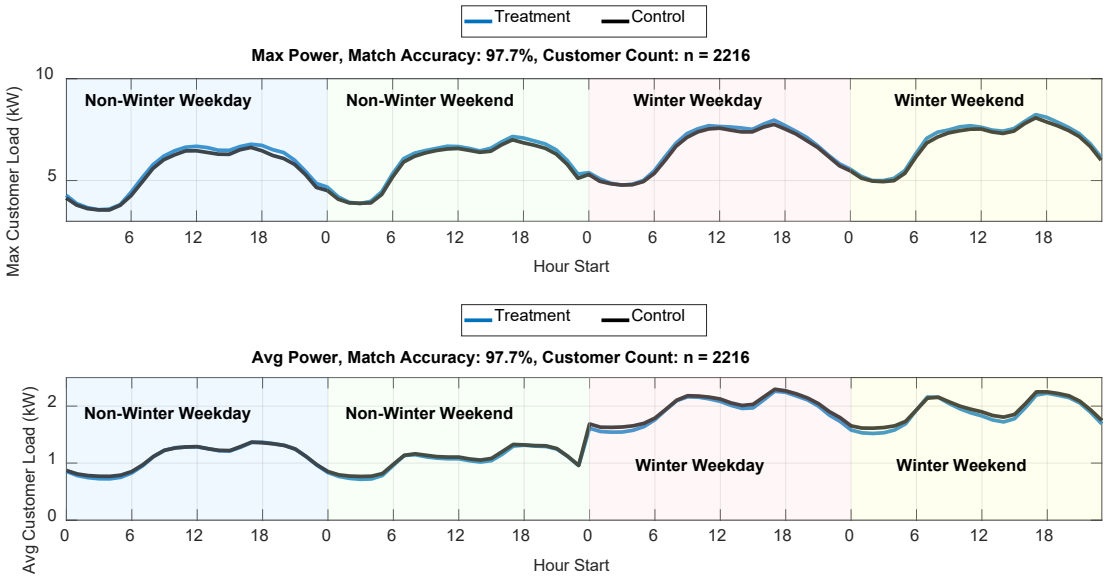


Figure 5: Residential CPP Pre-Pilot Control & Treatment Load Profile Comparison



The match accuracies compare load curves from both control and treatment. Data used for match accuracy are defined by the start hour of day (0 to 23), season (non-Winter or Winter), day type (Weekday or Weekend) and load type (average or maximum). This provides a total of 192 unique data points (hour × season × day type × load type) used to find an individual 1:1 control treatment match. As such, these match accuracies indicate a highly similar TOU and CPP control groups for their respective treatment groups. Notably, samples sizes are less than that provided in Table 5, this is a result of cleaning processes summarized in Table 68.

In addition to ensuring Pre-Pilot treatment and control loads are similar, it is valuable to analyze that baseline characteristics which influence diversity between treatment and control such as income, residents per household, year built, living space and dwelling style are compared. Unlike average and peak loads which are integral to control group selection, these baseline characteristics are not accounted for directly during control group selection. Refer to Attachment VI: Control Group Selection Non-Load Variables for data on baselines load characteristics for control, treatment, and the Nova Scotia population.

In summary, the analysis of baseline characteristics (i.e. income, residents per household, year built, and housing style) demonstrated that the control and treatment groups exhibit similar distributions to each other and to the population. However, living space is one metric that is similar between control and treatment groups but is approximately 13% larger (200 ft^2) than the population average. The difference in dwelling size combined with increased electric space heating penetration in TVP (71%) relative to the residential population (≤%60)[4] are expected to be main driving factors[5] as to why TVP customers consume approximately 2,450 kWh, or 24%, more than the average residential SOR customer (refer to Table 7).

Table 7: Average Residential Annual Energy Consumption (SOR & TVP)[6]

Group	Energy (kWh)
SOR	10,225
TVP	12,678

2.1.1 Eco Shift

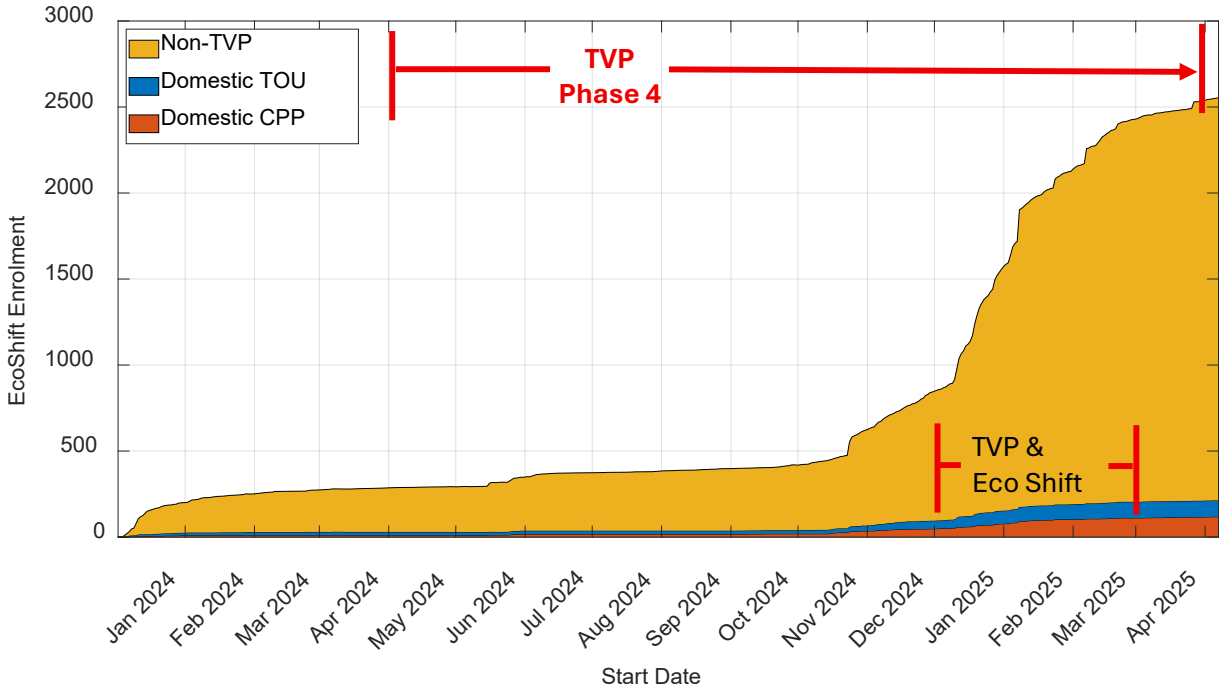
New to the TVP evaluation this year, is the analysis of E1's Eco Shift program combined with TVP customers. As of the end of TVP Phase 4, enrolment 2,500 participants were enrolled in E1's Eco Shift program, 209 of which were also TVP participants. A timeline of Eco Shift and TVP participants enrolled in the program during Phase 4 of the TVP evaluation is visualized in Figure 6.

[4] M12349 – 2025 Load Forecast Report, Figure 20, page 24. June 27, 2025.

[5] Statistics Canada. (2013). *Households and the environment: Energy use (2011)*. Catalogue no. 11-526-S. Government of Canada. https://www150.statcan.gc.ca/n1/en/pub/11-526-s/11-526-s2013002-eng.pdf

[6] Excluding net metering, seasonal and charitable rates within the domestic rate class.

Figure 6: Eco Shift Enrolment Timeline (TVP Phase 4 Period)



Additional analysis on the device type indicated that a majority of customers on both TVP and Eco Shift only had smart thermostats installed (87.6%, n=183), where those with EVs only represent (9.1%, n=19), and customers with both smart thermostats and EVs (3.4%, n=7). Notably, Eco Shift participants with smart thermostats often had multiple smart thermostats.

With respect to control group selection, all 209 identified TVP Eco Shift participants were matched with a control customer on the SOR (i.e. non-TVP) who did not participate in the Eco Shift program.

2.1.2 E1 Program Balancing

As discussed in methodology, E1 program participation is accounted for in control group selection, refer to Attachment III: Methodology. The results indicate that E1 program participation across all sub-groups (e.g. Cohort, Heating Type) has been balanced, achieving an overall balance accuracy of 99.1% defined by equation (3).

2.2 Commercial TOU & CPP

The same methodological approach as used with residential control group (with exception to Neighbourhood Criteria, Heating Classification, and Eco Shift) was used in attempting to select a control group for Small General and General (i.e. Commercial) TOU and CPP rates. The load profiles comparison of the potential control group is provided for Small General (TOU and CPP) and General (TOU and CPP), respectively, in Figure 7, Figure 8, Figure 9, and Figure 10. The results indicate poor matching for control selection as reflected in the low match accuracy, suggesting these control

groups are unsuitable. This result is similar to previous Phases, as such, the regression analysis for these TVP Tariffs will be within-subject (i.e. semi-DiD).

Samples sizes shown in Figure 7 through Figure 10 are less than that provided in Table 5, this is a result of cleaning processes summarized in Table 68.

Figure 7: Small General TOU Pre-Pilot Control & Treatment Load Profile Comparison

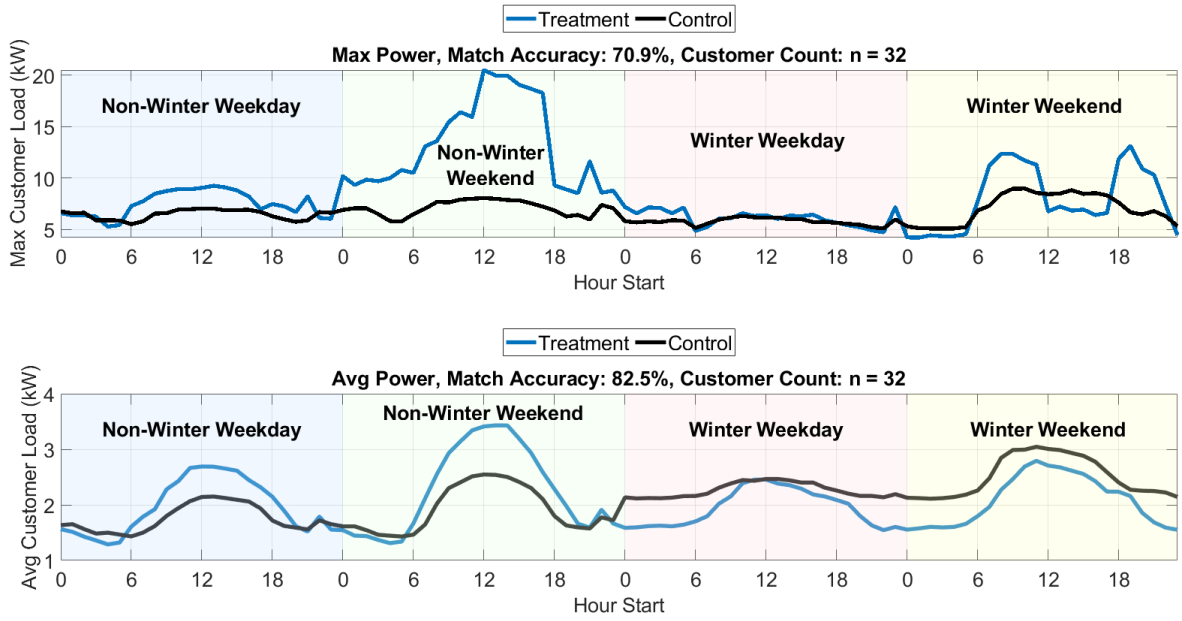


Figure 8: Small General CPP Pre-Pilot Control & Treatment Load Profile Comparison

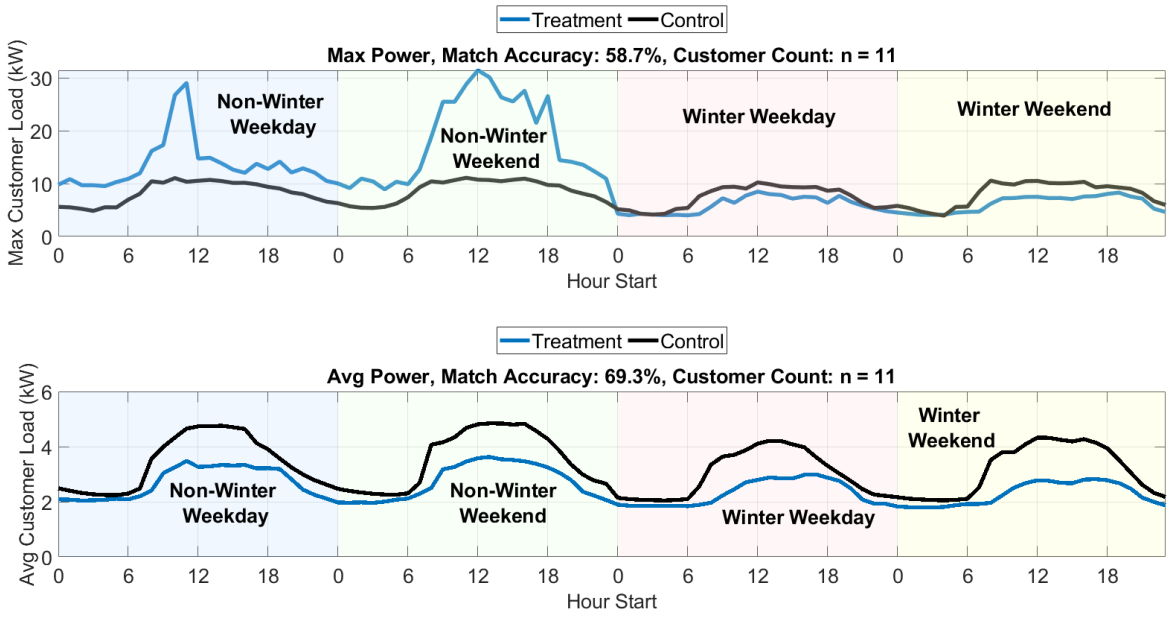


Figure 9: General TOU Pre-Pilot Control & Treatment Load Profile Comparison

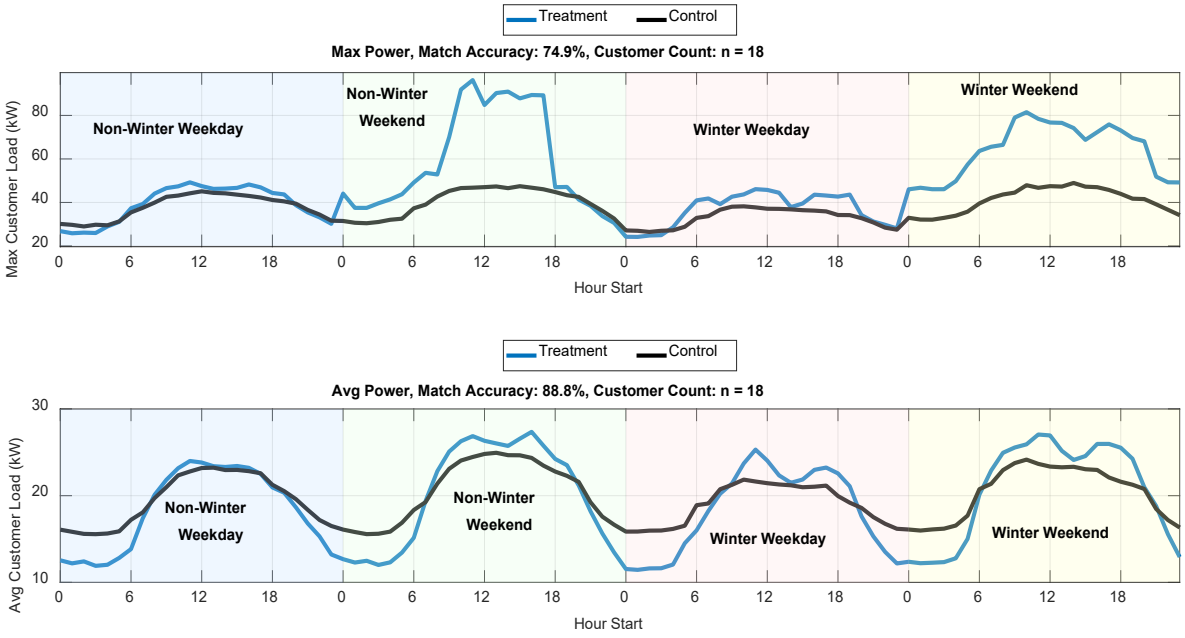
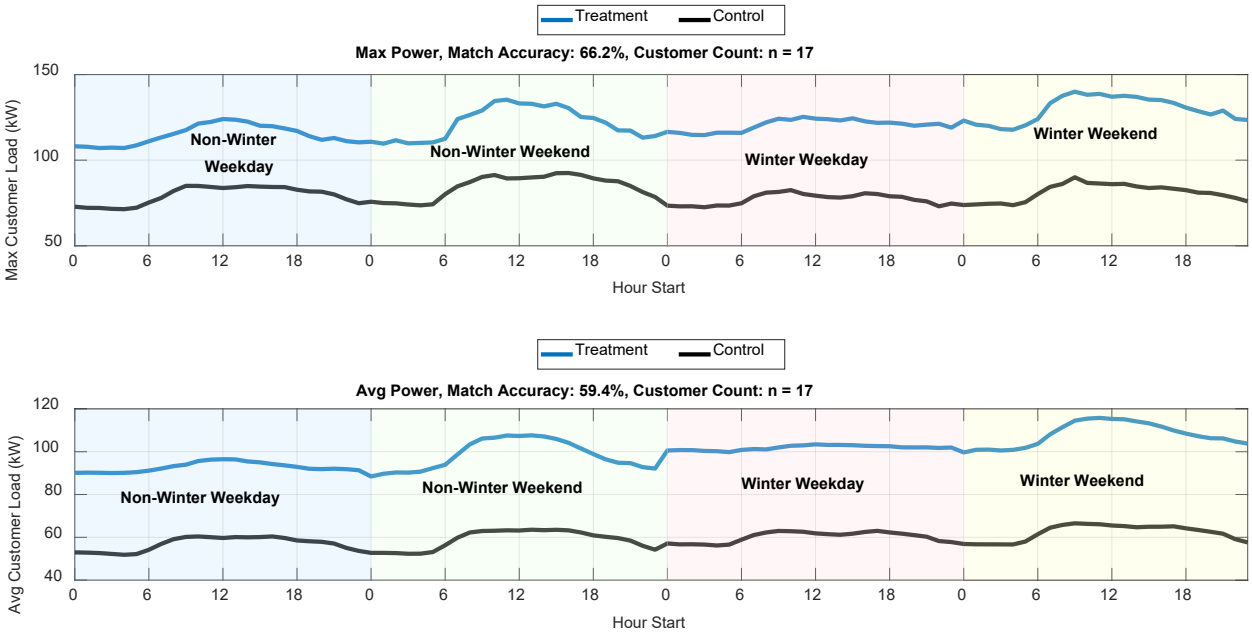


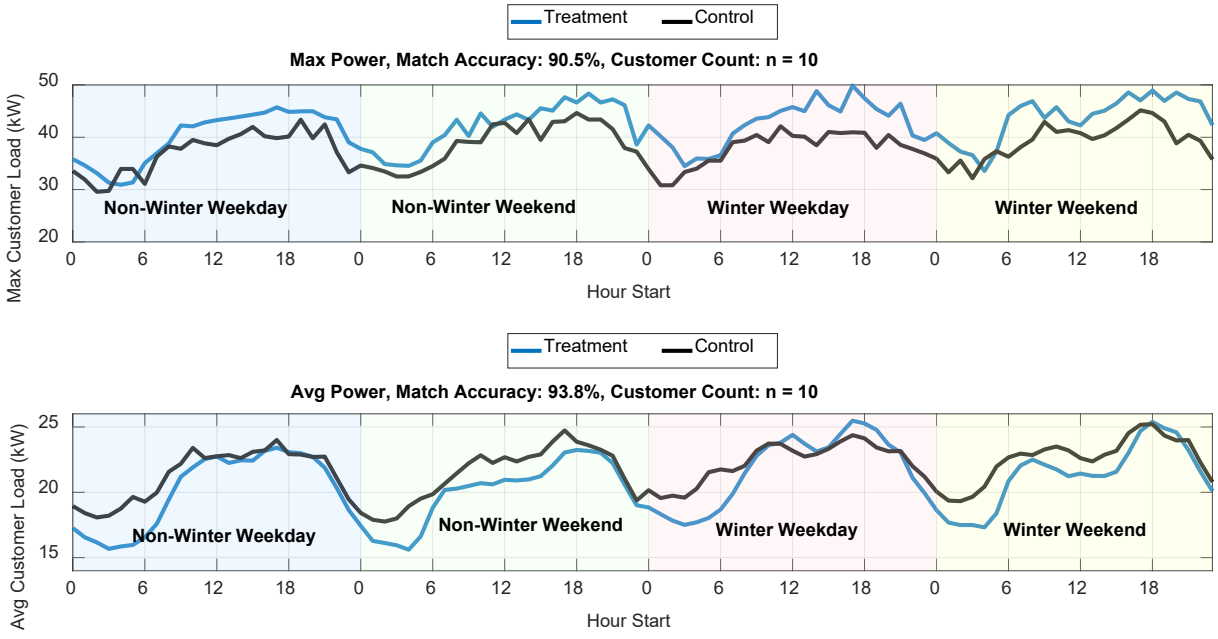
Figure 10: General CPP Pre-Pilot Control & Treatment Load Profile Comparison



2.3 MURB TOU

For MURB TOU, the control group selection model was successful (Match Accuracy ≥ 90%) in selecting a 1:1 control for the ten MURB TOU treatment customers, refer to load profiles below in Figure 11.

Figure 11: MURB TOU Pre-Pilot Control & Treatment Load Profile Comparison



The control group selection load comparison results for MURB TOU indicate a good match accuracy and thus a control group will be used for this subset of commercial customers.

2.4 CPP Reference Days

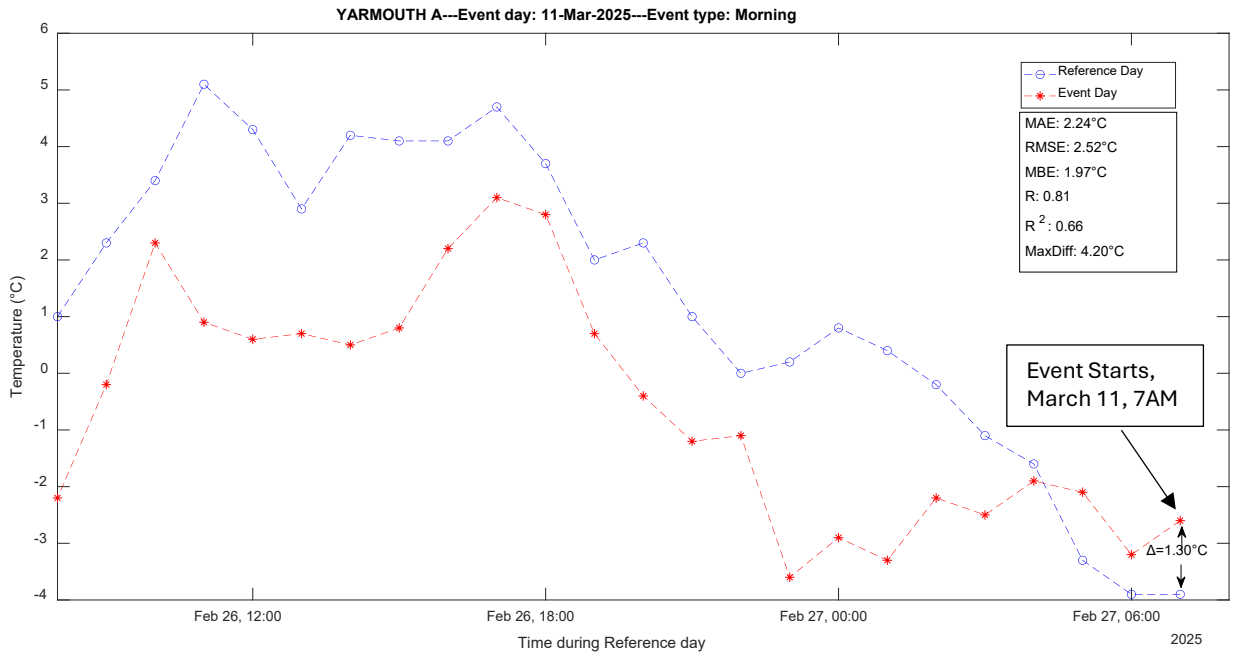
The CPP reference days were selected for Phase 4 are summarized in Table 8.

Table 8: Phase 4 CPP Event Reference Day Results

Event Day	HALIFAX AIRPORT	KENTVILLE CDA CS	NAPPAN AUTO	SHEARWATER RCS	SYDNEY AIRPORT	TRACADIE	WESTERN HEAD	YARMOUTH AIRPORT
12/4/2024	12/3/2024	12/3/2024	12/3/2024	12/3/2024	12/3/2024	12/3/2024	12/3/2024	12/3/2024
12/15/2024	12/14/2024	12/14/2024	12/14/2024	12/14/2024	12/14/2024	12/14/2024	12/14/2024	12/14/2024
12/20/2024	12/27/2024	1/3/2025	12/2/2024	12/2/2024	1/3/2025	12/2/2024	1/3/2025	12/2/2024
12/22/2024	12/7/2024	12/7/2024	12/7/2024	12/7/2024	12/7/2024	1/5/2025	1/5/2025	1/5/2025
12/23/2024	1/6/2025	1/6/2025	1/6/2025	1/6/2025	12/21/2024	1/6/2025	1/6/2025	1/6/2025
1/21/2025	1/23/2025	1/29/2025	1/29/2025	1/30/2025	1/23/2025	1/29/2025	1/16/2025	1/16/2025
1/22/2025	1/23/2025	2/11/2025	2/11/2025	1/23/2025	1/23/2025	1/23/2025	1/16/2025	2/11/2025
2/2/2025	2/15/2025	2/9/2025	2/9/2025	2/15/2025	1/25/2025	2/16/2025	2/15/2025	1/25/2025
2/5/2025	1/30/2025	1/30/2025	1/30/2025	1/30/2025	1/30/2025	1/30/2025	2/18/2025	2/18/2025
2/6/2025	1/23/2025	1/23/2025	1/23/2025	1/23/2025	1/23/2025	1/23/2025	1/23/2025	2/19/2025
3/4/2025	2/13/2025	2/13/2025	2/18/2025	2/13/2025	2/13/2025	2/13/2025	2/19/2025	2/19/2025
3/10/2025	2/21/2025	3/14/2025	3/14/2025	3/14/2025	3/14/2025	3/14/2025	2/21/2025	2/24/2025
3/11/2025	2/27/2025	3/13/2025	3/13/2025	2/27/2025	2/20/2025	2/20/2025	2/27/2025	2/27/2025

For example, the CPP event day on December 4, 2024, has the same reference day for all eight weather stations (December 3, 2024). Although each weather station is independently assessed for the most similar temperature data, the analysis indicates December 3, 2024, was the most similar temperature day to the event day for all weather stations. On the contrary, the event on March 11, 2025, has different reference days for some weather stations. For example, for the March 11 event, customers nearest to the Sydney A weather station, the best reference day is February 20, 2025, whereas customers nearest to Kentville CDA CS, the best reference day is March 13, 2025, and alternatively for Yarmouth A, the best reference day is February 27, 2025. A comparison between reference day and event day in Figure 12 shows the temperature profile for a 24-hour period prior to the March 11 morning event which started at 7:00 AM.

Figure 12: CPP Event Reference Day Temperature Profile Example



From Figure 12, it is clear that the temperature on the reference day and event day are similar with a mean absolute error (MAE) of 2.24 °C, root mean square error (RMSE) of 2.52 °C, mean bias error (MBE) of 1.97 °C and R^2 = 0.66. As well, the two 24-hour periods are positively correlated to each other (R = 0.81) with a difference in temperature of 1.3 °C at the beginning of the event.

3 Residential TOU Tariff Impacts

This section presents the analysis results for load and economic impacts of Residential TOU tariffs for all cohorts in Phase 4. The goal of the residential TOU pilot is to encourage customers to shift their electricity usage from peak periods to off-peak periods when system utilization is typically lower. This is done by presenting customers with the opportunity to lower their energy bills if they participate in load shifting. The price differential is derived from system savings created in the near-term in the form of reduced fuel and purchased power costs, and over the longer-term in the form of avoided generation, transmission, and distribution infrastructure costs.

The impacts of the TOU Tariff are evaluated within this section. Table 9 summarizes the characteristics of the residential TOU participants that were included in the analysis of the load and economic impacts. Notably, the number of TOU participants in Cohort 4 is almost three times larger than that in cohorts 1, 2, and 3 combined. Also, participants with steady electric heating system are more prevalent than participants with other heating types, while those with de-electrified heating are the least frequent among TOU participants in Phase 4.

Table 9: Summary of Residential TOU Sample Size[7]

Parameter	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Sample Size	430	190	1,016	3,302	4,938
Heating Type					
Steady Electric	48%	65%	61%	61%	60%
Steady Non-Electric	26%	18%	22%	25%	24%
Electrified	22%	11%	11%	9%	10%
De-Electrified	4%	6%	6%	5%	6%
Region					
HRM	61%	58%	58%	58%	58%
Rest of Nova Scotia	39%	42%	42%	42%	42%

3.1 Load & Usage Impacts

This section presents and discusses the electrical load impact from the residential TOU Tariff.

3.1.1 Change in Load during Peak Periods

Table 10 summarizes the results of the analysis for morning and evening TOU peak hours for each cohort and for all cohorts combined. The average load reductions are presented along with their margin of error (MoE) at a 90% confidence level. While all cohorts exhibit statistically significant load reduction during morning and evening peak hours, TOU participants achieved slightly higher load reduction during the evening peak hours. Overall, TOU participants demonstrated load reductions of 0.15 kW and 0.17 kW, corresponding to relative load reductions of 7.4% and 7.9% during morning and evening periods, respectively. The overall average load reduction across all residential TOU participants is 0.16 kW.

[7] Sample size in this table differs from the participation summary found in Table 5 as some participants are removed due to not meeting AMI data criteria necessary for the regression analysis (refer to cleaning steps in Table 69)

Table 10: Change in Load during TOU Peaks for Residential TOU Participants

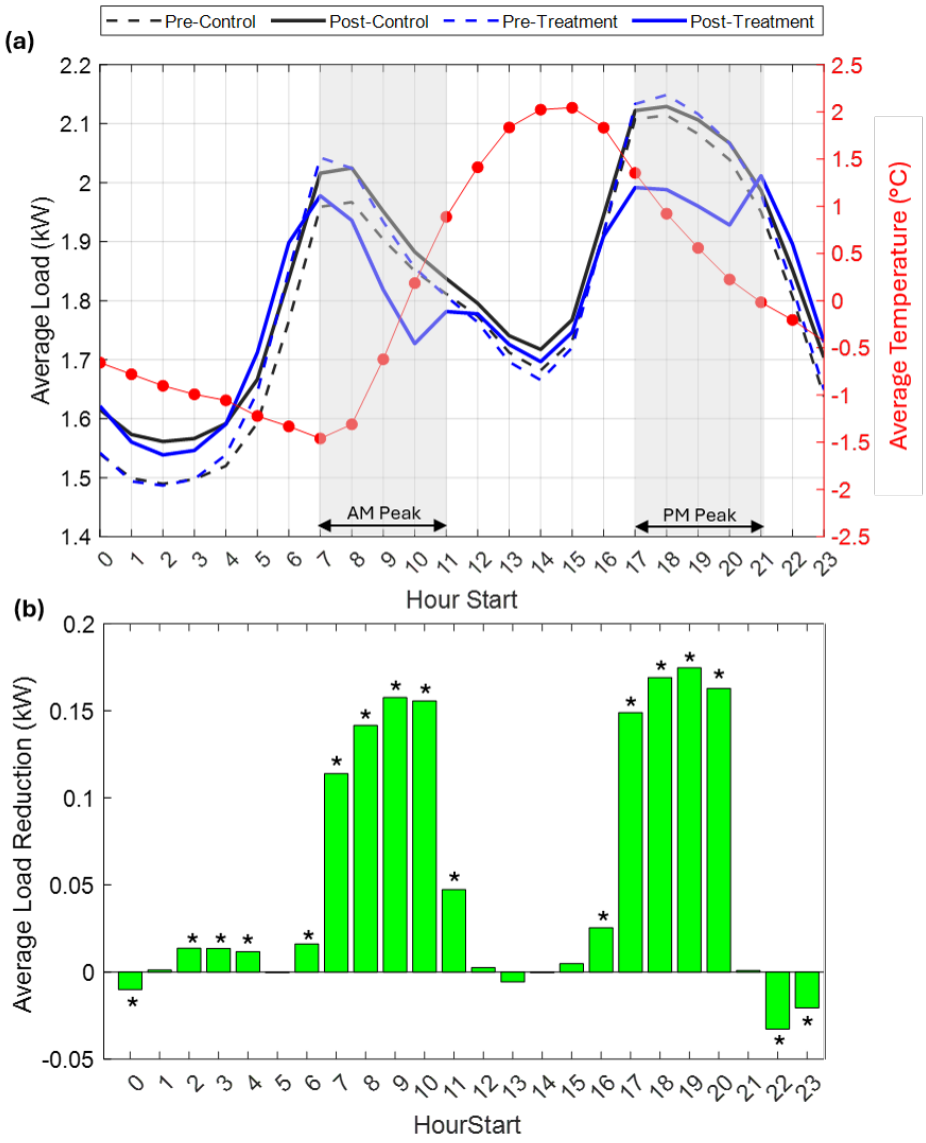
Parameters	Morning Peak Periods					Evening Peak Periods				
	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Avg. Load Reduction (kW)[a]	0.18 ± 0.01	0.28 ± 0.02	0.14 ± 0.01	0.13 ± 0.01	0.15 ± 0.01	0.20 ± 0.01	0.31 ± 0.02	0.20 ± 0.01	0.14 ± 0.01	0.17 ± 0.01
Avg. Load – Residential TOU Participants Pre-Pilot (kW)	1.9	2.3	2.0	1.9	2.0	2.1	2.4	2.2	2.1	2.1
Relative Avg. Load Reduction (%)[a]	9.2%	12.3%	7.1%	6.7%	7.4%	9.7%	13.0%	9.2%	6.8%	7.9%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

Figure 13a illustrates the load profiles for residential TOU participants and the control group during the pre-pilot and pilot periods, along with the corresponding variation in outdoor temperature. Additionally, it highlights that residential TOU participants (post-treatment, blue line) exhibit load shifts during morning and evening peak hours, compared to the post-control group (black line).

Figure 13b shows the hourly load reduction by residential TOU customers that exhibit significant increase in load reductions during morning and evening peak hours. It indicates significant load shifts by TOU participants during TOU peak periods.

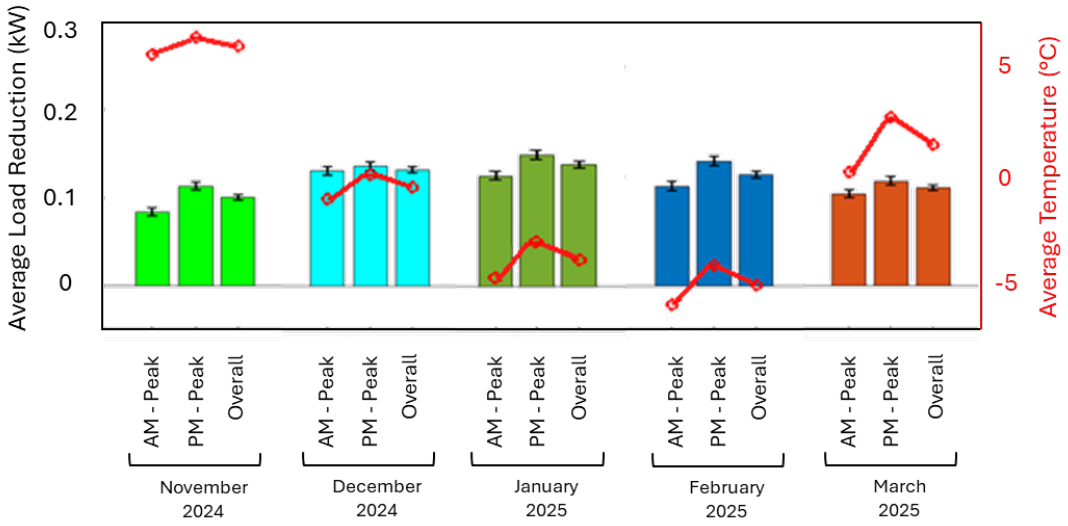
Figure 13: (a) Winter Hourly-Average Load Shapes for Residential TOU Participants (pre/post, treatment/control) with Average Outdoor Temperature; (b) Hourly Average Load Reduction (kW)



* Statistically Significant (p_Value≤0.05)

Figure 14 illustrates the impact of residential TOU in terms of average load reduction (kW), together with the average outdoor temperature (°C) during peak hours by month over the Winter period from November 2024 to March 2025. Residential TOU participants demonstrated statistically significant load reductions during both morning and evening peak hours across all Winter months. Notably, TOU participants exhibit the highest load reduction during evening peak hours in January and February when they experienced the coldest weather.

Figure 14: Average Load Reduction (kW) and Average Temperature during Residential TOU Peak Periods in Winter for the Months of November, December, January, February, and March



Change in Load by Space Heating Classes during TOU Peak Hours

Table 11 summarizes the average load reductions during morning and evening TOU peak hours for space heating classes of all cohorts combined in Phase 4. The load reductions by all space heating classes are statistically significant. Specifically, the TOU participants with steady electric space heating system exhibit the highest average load reductions of 0.18 kW and 0.20 kW, corresponding to relative load reductions of 7%, during morning and evening peak hours, respectively. As expected, the TOU customers with steady non-electric space heating systems demonstrate the lowest absolute load reductions of 0.07 kW and 0.1 kW during morning and evening peak hours. The TOU participants who electrified their heating system, by transitioning from non-electric to electric space heating, exhibit load reductions of 0.07 kW and 0.14 kW during morning and evening peak hours.

Table 11: Change in Load during TOU Peak Hours during Non-Holiday Weekdays in Winter by Heating Class for Residential TOU Participants

Parameters	Morning				Evening			
	De-Electrified	Electrified	Steady Electric	Steady Non-Electric	De-Electrified	Electrified	Steady Electric	Steady Non-Electric
Avg. Load Reduction (kW)[a]	0.15 ± 0.01	0.07 ± 0.01	0.18 ± 0.03	0.07 ± 0.01	0.12 ± 0.01	0.14 ± 0.01	0.20 ± 0.01	0.10 ± 0.01
Avg. Load – Residential TOU Participants, Pre-Pilot (kW)	1.4	1.7	2.5	0.8	1.6	1.9	2.6	1.1
Relative Avg. Load Reduction (%)[a]	10.4%	4.3%	7.0%	8.2%	7.5%	7.0%	7.3%	9.8%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓	✓	✓

[a] *Positive* values represent 'Load Reduction' and *Negative* values represent 'Load Increase'.

Change in Load by Region, Income Level, and Residents per Household

Figure 15 illustrates the average load reduction achieved by TOU participants according to the region of premises in Nova Scotia. While no significant difference in load reduction during morning hours is observed between participants in greater Halifax area and those located in the rest of Nova Scotia, the TOU participants in Halifax area exhibit higher load reduction during evening peak hours compared to those located in the rest of Nova Scotia. However, the difference of overall load reductions is not statistically significant between Halifax area and the rest of Nova Scotia.

Figure 15: Average Load Reduction during Morning and Evening Peak Hours for TOU Participants Located in the Greater Halifax Area and the Rest of Nova Scotia

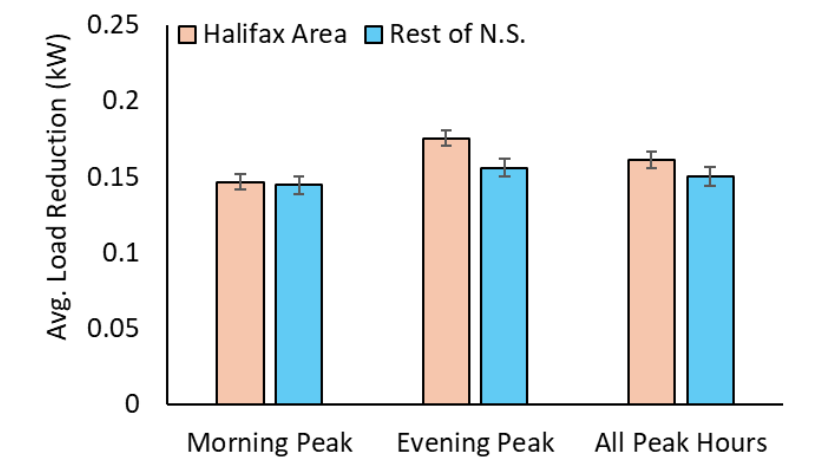
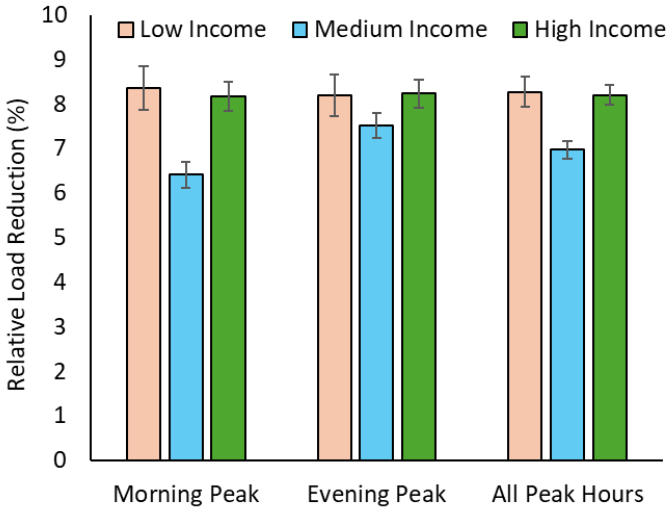


Figure 16 illustrates the average load reduction by income level (Low, Medium, and High-income levels), where TOU participants with lower, medium and higher income levels exhibit relative load reductions of 8.3%, 7.0%, and 8.2% corresponding to overall load reductions of 0.15 kW, 0.14 kW, and 0.19 kW, respectively (Table 12) across TOU related periods.

Figure 16: Relative Average Load Reduction (%) by Income Levels of TOU Participants during Morning and Evening TOU Peak Hours as well as Overall across All Peak Periods



Notably from Figure 16, there is no discernable trend in relative load reduction (%) associated with change in income. However, when absolute load reductions are compared, higher income participants demonstrate statistically significantly higher load reductions (0.19 ± 0.01 kW) relative to low- (0.15 ± 0.01 kW) and medium-income (0.14 ± 0.01 kW) participants, respectively.

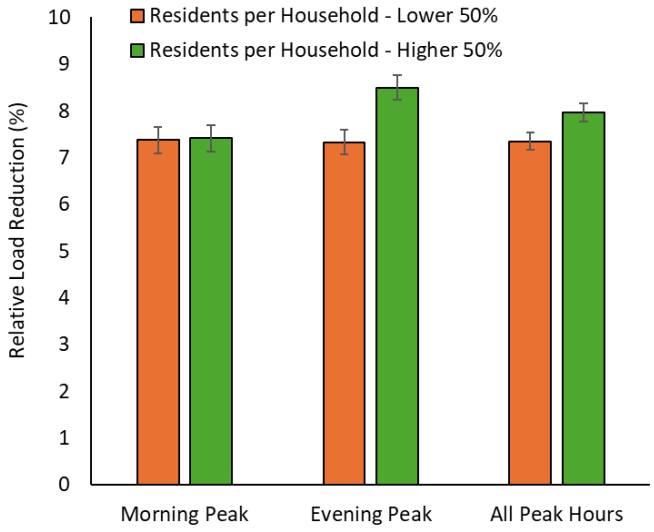
Table 12: Change in Load during TOU Peak Hours by Income Level for Residential TOU Participants

Parameters	Low-Income			Medium-Income			High-Income		
	AM Peak	PM Peak	All Peak Hours	AM Peak	PM Peak	All Peak Hours	AM Peak	PM Peak	All Peak Hours
Avg. Load Reduction (kW)[a]	0.14 ± 0.01	0.15 ± 0.01	0.15 ± 0.01	0.12 ± 0.01	0.16 ± 0.04	0.14 ± 0.01	0.18 ± 0.01	0.19 ± 0.01	0.19 ± 0.01
Avg. Load – Residential TOU Participants, Pre-Pilot (kW)	1.7	1.8	1.8	1.9	2.1	2.0	2.2	2.4	2.3
Relative Avg. Load Reduction (%)[a]	8.4%	8.2%	8.3%	6.4%	7.5%	7.0%	8.2%	8.2%	8.2%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

Figure 17 illustrates the load reduction by TOU participants according to residents per household, segmented at the lower 50% and higher 50% for the comparison. The households with more residents achieved an overall load reduction of 0.18 kW which is greater than 0.13 kW achieved by the lower households. It is worth noting that the average household size differs between the segments, with 2.03 residents in the lower 50% and 2.79 residents in the higher 50%.

Figure 17: Average Load Reduction (kW) by Residents-per-Household (lower 50% vs. higher 50%) for Morning and Evening TOU Peak Hours as well as All Peak Periods

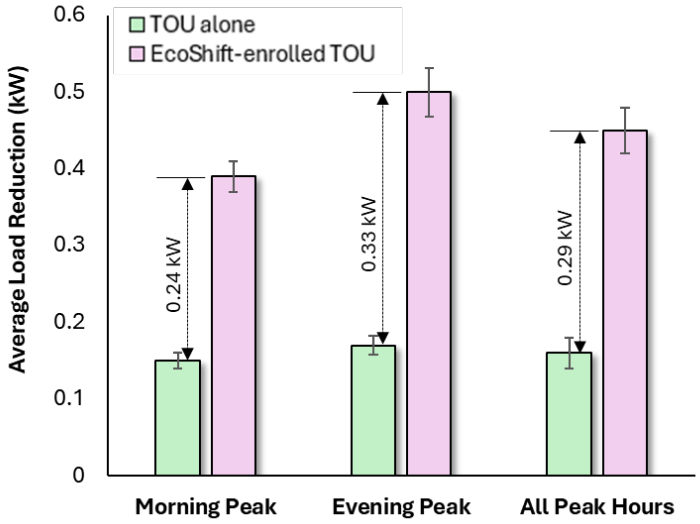


Change in Load with Eco Shift

E1's Eco Shift is a DR initiative offered separately from TVP and was implemented within subset of the TVP treatment participants who opted into both programs. It is designed to encourage load reduction during peak hours by connecting with smart devices that can automatically reduce electricity usage during peak demand periods. Refer to Attachment III: Methodology (Table 71) for a list of Eco Shift events.

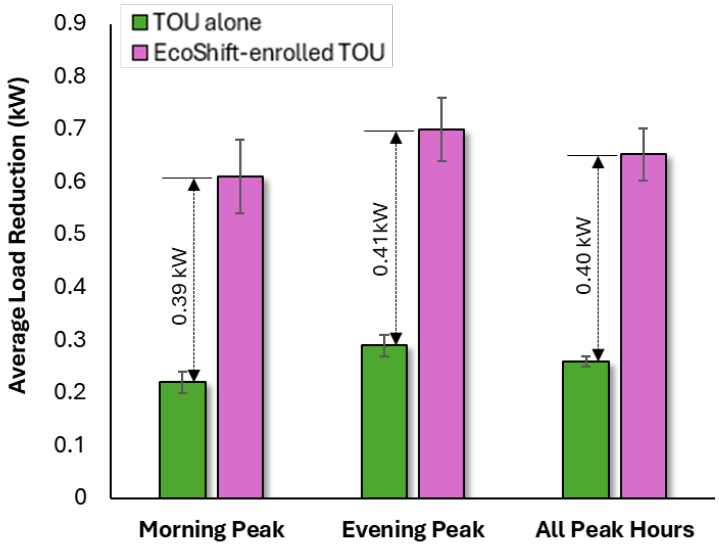
NS Power evaluated the overlapping effect of Eco Shift enrolled customers on TOU load impact during TOU peak periods without event calls, as well as the incremental load reduction due to Eco Shift event calls compared to non-Eco Shift residential TOU customers during Eco Shift events. The analysis uses a triple-difference (DDD) regression analysis (equation (8)) to estimate the incremental effect of overlapping Eco Shift enrollment on TOU impact. The analysis reveals that TOU participants that also enrolled in Eco Shift reduced their overall load by an additional 0.29 kW ± 0.01 kW during all TOU peak hours, where they reduced their load by additional 0.24 ± 0.01 kW and 0.33 kW ± 0.02 kW during morning and evening TOU peak hours, respectively (Figure 18). The analysis shows that the TOU program alone led to an overall load reduction of 0.15 ± 0.002 kW, indicating the overlapping Eco Shift-enrolled TOU participants achieved a greater overall load reduction of 0.44 kW. Refer to Figure 18 for both the TOU customers without Eco Shift (TOU alone) and TOU Enrolled Eco Shift load impacts.

Figure 18: Average Load Reductions for Residential TOU Participants vs. Eco Shift-Enrolled Residential TOU Participants during TOU Peak Hours



Furthermore, the analysis shows that TOU participants enrolled in Eco Shift demonstrated an additional load reduction of 0.40 ± 0.04 kW during Eco Shift events. Specifically, TOU participants reduced their load on average by an additional 0.39 ± 0.05 kW in the morning and 0.41 ± 0.04 kW in the evening (Figure 19). Participants experienced an overall load reduction of 0.26 ± 0.02 kW due to the TOU program alone during Eco Shift events. This indicates that Eco Shift–enrolled TOU participants achieved a total load reduction of 0.66 kW during Eco Shift events when combining both the TOU effect and the additional Eco Shift impact (Figure 19).

Figure 19: Load Reductions for Residential TOU Participants vs. Eco Shift-Enrolled Residential TOU Participants during Combined Peak-Event (TOU + Eco Shift) Morning and Evening Event Hours, Reflecting the Eco Shift Event Driven Additional Load Impact



In conclusion, the customers with overlapping participation in the Eco Shift program provide a statistically significant additional impact on load reduction, relative to TOU load impact alone. This effect was further enhanced during Eco Shift DR events.

3.1.2 Snapback Effect

While the TOU participants exhibit relatively small but statistically significant load increase of 0.014 kW during evening snapback period, they reduced their electricity usage by 0.013 kW during morning snapback hours, which is also statistically significant (Table 13). However, overall, participants experienced a statistically insignificant change in their load during morning and evening snapback periods (Table 13).

Table 13: Snapback Effect for Residential TOU Participants

Parameters	Avg. Load Reduction [a] (kW)	Significance (p_Value≤0.05)
Morning Snapback	0.013 ± 0.004	✓
Evening Snapback	-0.014 ± 0.005	✓
Overall Snapback	-0.002 ± 0.003	X

[a] Positive and Negative values represent 'Reduction' and 'Increase' in electricity usage, respectively.

3.1.3 Change in Load during Highest ANL Hours

Figure 20 depicts the distribution of Top 20, 50, and 88 highest ANL hours for residential TOU participants during morning peak, evening peak, and off-peak hours as well as weekends and holidays. As provided in Figure 20a-c, the majority of the highest ANL hours occurred during weekdays, and specifically on morning and evening peak hours.

Figure 20: Distribution of Top 20, Top 50 and Top 88 ANL Hours by Day Type (Weekday / Weekend) and Residential TOU Period

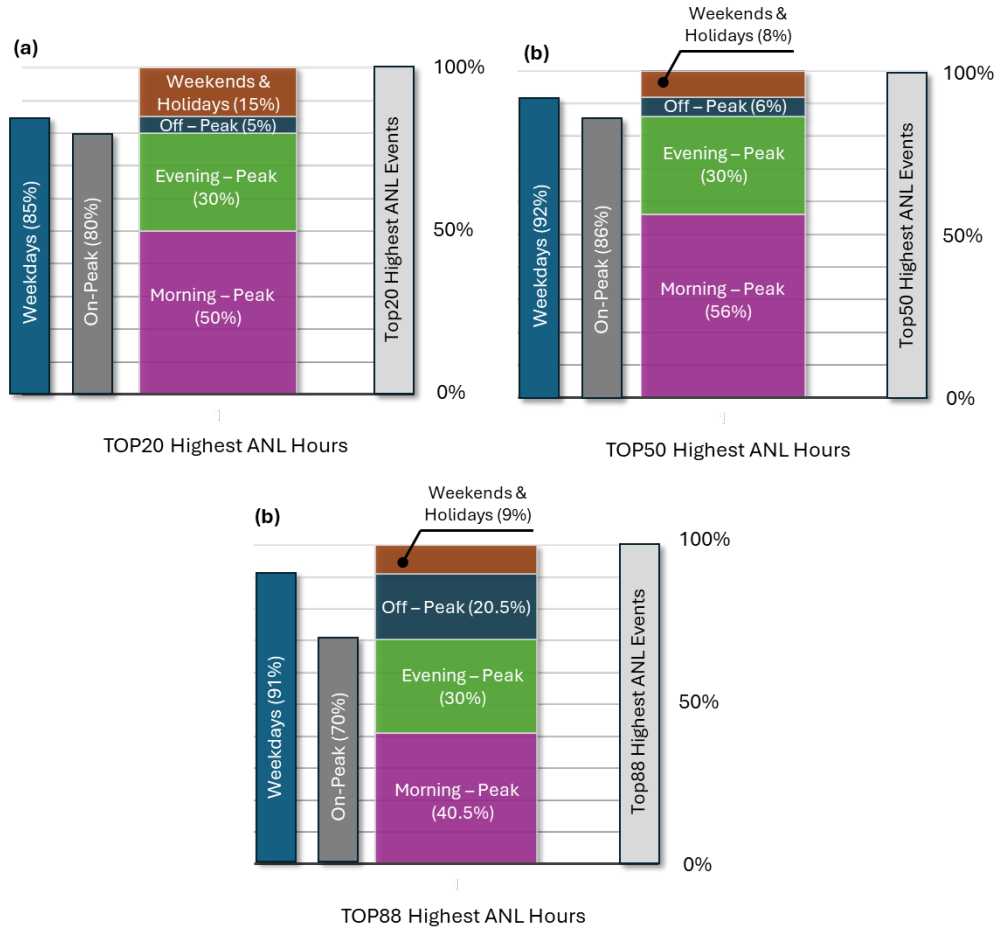


Table 14 summarizes the estimated changes in load during the highest ANL hours overall, as well as during ANL hours that coincide with TOU peak periods.

Results indicate that residential TOU participants exhibit statistically significant load reduction during the top 20, 50, and 88 highest ANL hours. When focusing specifically on ANL hours that coincide with TOU peak periods, participants achieved significant relative load reduction of approximately 6%, corresponding to absolute load reduction of 0.17 kW, during top 20, 50, and 88 hours that coincide with TOU peak hours, which are higher than their corresponding load reductions of 0.16 kW, 0.14 kW, and 0.13 kW during the highest ANL hours.

Table 14: Change in Load (kW) during Highest Winter ANL Hours for Residential TOU Participants

Parameters	Highest ANL Hours			ANL Hours Coincide TOU Peak Periods		
	Top 20	Top 50	Top 88	Top 20	Top 50	Top 88
Avg. Load Reduction (kW)[a]	0.16 ± 0.04	0.14 ± 0.03	0.13 ± 0.02	0.17 ± 0.03	0.17 ± 0.03	0.17 ± 0.02
Avg. Load – Residential TOU Participants, Pre-Pilot (kW)	2.86	2.78	2.70	2.85	2.76	2.72
Relative Avg. Load Reduction (%)[a]	5.6%	5.2%	4.8%	6.0%	5.9%	6.2%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

3.1.4 Change in Usage

Table 15 summarizes changes in daily electricity usage level for cohorts 1 to 4 and all cohorts combined during non-holiday weekdays and holiday weekends in Winter. All cohorts exhibit statistically significant reduction in daily usage level during non-holiday weekdays in Winter. All cohorts reduced their daily usage during holiday weekends in Winter as well. Overall, all cohorts exhibit a statistically significant average load reduction of 1.39 kWh during non-holiday weekdays. Notably, TOU participants also demonstrated an average load reduction of 0.6 kWh on holidays and weekends, which is statistically significant.

Table 15: Change in Daily Electricity Usage (kWh/day) by Cohort for Residential TOU Participants

Parameters	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Winter, Non-Holiday Weekdays					
Avg. Usage Reduction (kWh/day)[a]	1.71 ± 0.21	2.70 ± 0.31	1.64 ± 0.14	1.10 ± 0.08	1.39 ± 0.06
Avg. Usage – Residential TOU Participants, Pre-Pilot (kWh/day)	39.4	50.4	43.2	43.4	43.4
Relative Usage Reduction (%)[a]	4.3%	5.4%	3.8%	2.6%	3.2%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓
Winter, Weekends / Holidays					
Avg. Usage Reduction (kWh/day)[a]	0.86 ± 0.33	1.91 ± 0.48	1.11 ± 0.22	0.32 ± 0.12	0.60 ± 0.10
Avg. Usage – Residential TOU Participants, Pre-Pilot (kWh/day)	41.2	52.1	45.0	44.6	44.8
Relative Usage Reduction (%)[a]	2.1%	3.7%	2.4%	0.7%	1.4%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓
Non-Winter					
Avg. Usage Reduction (kWh/day)[a]	0.79 ± 0.08	0.53 ± 0.15	0.55 ± 0.06	n/a	0.54 ± 0.04
Avg. Usage – Residential TOU Participants, Pre-Pilot (kWh/day)	25.8	28.6	26.3		25.5
Relative Usage Reduction (%)[a]	3.1%	1.9%	2.1%		2.1%

[a] Positive values represent 'Usage Reduction' and Negative values represent 'Usage Increase.'

Table 16 presents changes in daily electricity usage levels by space heating. During non-holiday weekdays in Winter, TOU participants with electrified space heating exhibit insignificant change in their daily usage level. Notably, this group of participants exhibit a significantly larger daily usage increase of 1.01 kWh/day, corresponding to 3.5% daily usage increase, during holidays and weekends. In contrast, participants with de-electrified heating systems demonstrate a daily usage reduction of 0.75 kWh/day during non-holiday weekdays, while they exhibit insignificant change in their daily usage during holiday/weekends. Participants with steady electric heating systems achieved daily usage reductions of 3.5% and 2.0%, corresponding to electricity usage reductions of 1.96 kWh and 1.14 kWh, respectively, during non-holiday weekdays and holidays and weekends. TOU customers with steady non-electric heating systems exhibit daily usage reduction of 0.15 kWh/day during non-holiday weekdays, while increasing their usage by 0.46 kWh/day during holiday weekends in Winter. For all TOU participants combined, savings are statistically significant for all days throughout the year and add up to 300 kWh annually on average.

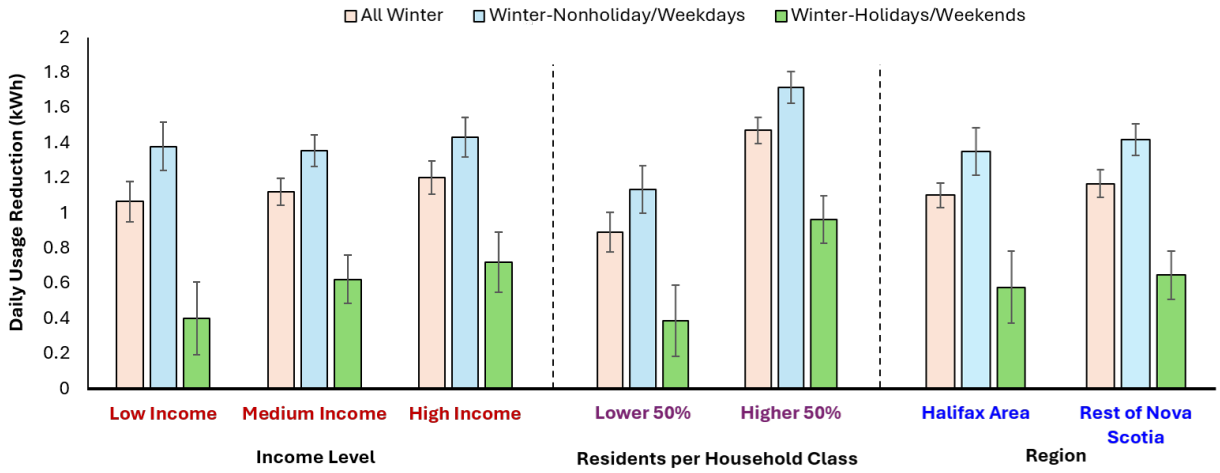
Table 16: Change in Daily Electricity Usage Level by Space Heating Type for All Cohorts of Residential TOU Participants

Parameters	De-Electrified	Electrified	Steady Electric	Steady Non-Electric
Winter, Non-Holiday Weekdays				
Avg. Usage Reduction (kWh/day)[a]	0.75 ± 0.20	-0.09 ± 0.14	1.96 ± 0.10	0.15 ± 0.07
Avg. Usage – Residential TOU Participants, Pre-Pilot (kWh/day)	38.5	27.7	55.4	20.4
Relative Usage Reduction (%)[a]	1.9%	-0.34%	3.5%	0.72%
Significance (p_Value≤0.05)	✓	X	✓	✓
Winter, Weekends / Holidays				
Avg. Usage Reduction (kWh/day) [a]	0.10 ± 0.31	-1.01 ± 0.22	1.14 ± 0.10	-0.46 ± 0.10
Avg. Usage – Residential TOU Participants, Pre-Pilot (kWh/day)	40.0	27.7	56.6	21.7
Relative Usage Reduction (%)[a]	0.2%	-3.5%	2.0%	-2.1%
Significance (p_Value≤0.05)	X	✓	✓	✓
Non-Winter				
Avg. Usage Reduction (kWh/day)[a]	0.90 ± 0.17	0.37 ± 0.10	0.74 ± 0.06	0.31 ± 0.08
Avg. Usage – Residential TOU Participants, Pre-Pilot (kWh/day)	24.5	22.5	29.5	21.6
Relative Usage Reduction (%)[a]	3.7%	1.7%	2.5%	2.1%
Significance (p_Value≤0.05)	✓	✓	✓	✓

[a] Positive values represent 'Usage Reduction' and Negative values represent 'Usage Increase.'

Further segmented changes in daily-usage level by income level, residents-per-household, and region, are shown in Figure 21. The participants from all segments above exhibit the highest daily load reduction (kWh/day) during non-holidays/weekdays. Notably, the households with higher 50% residents-per-household demonstrated significantly higher daily usage reduction during Winter compared to the households with lower 50% residents-per-household. In contrast, no statistically significant differences of daily usage reduction were observed among participants with low-, medium-, and high-income levels. Likewise, the daily usage reductions between TOU customers in Halifax area and those in the rest of Nova Scotia were not statistically different.

Figure 21: The Impact of Residential TOU Participants on Daily Usage Level (kWh/day) by Participants from Different Segments of Income-Level, Residents-per-Household, and Region



3.2 Economic Impacts

This section presents and discusses the impact of residential TOU tariffs on the electricity bill as well as price elasticity.

3.2.1 Change in Electricity Bills

Table 17 summarizes the applicable tariffs used for residential TOU impact on billing. Tariff details can be found in Attachment I: Riders and Tariff Structure.

Table 17: Tariffs Used for Analyzing Residential TOU Impact on Electricity Bill

Customer Type and Period	Applicable Tariff
Control, Pre-Pilot	Domestic Standard Tariff
Control, Pilot	Domestic Standard Tariff
Treatment, Pre-Pilot	Domestic Standard Tariff
Treatment, Pilot	Domestic TOU Tariff

Table 18 presents the bill impact for residential TOU, where participants exhibit an overall annual average bill saving of $0.30 per day, corresponding to 5.5% of average annual bill. This amount of annual bill saving is statistically significant. The residential TOU participants achieved an average bill savings of $1.54 per day during non-Winter, corresponding to 32.6% of average non-Winter bill. The non-Winter savings are primarily due to a reduced rate per kWh during the non-Winter period (11.426 ¢/kWh under the TOU Tariff) compared to 16.931¢/kWh for the Domestic SOR. In contrast, the TOU participants experienced an overall bill increase of $1.34 per day during Winter despite significant load reduction (Table 10). This is because the TOU rate during peak hours is approximately

twice the TOU rate during off-peak hours,[8] for which peak load reductions and energy savings could not fully offset increase in rate during the Winter period.

Table 18: Change in Daily Electricity Bill for All Cohorts of Residential TOU Participants

Parameters	Winter Non-Holiday Weekdays	Winter Holiday/ Weekends	Winter Overall	Non-Winter	Annual Average
Avg. Bill Savings ($/day)[a]	-2.05 ± 0.01	0.12 ± 0.01	-1.34 ± 0.01	1.54 ± 0.04	0.30 ± 0.01
Avg. Bill – Residential TOU Participants, Pre-Pilot ($/day)	8.1	8.3	8.1	4.7	5.4
Relative Avg. Bill Savings (%)[a]	-25.5%	1.5%	-16.5%	32.6%	5.5%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓

[a] *Positive* values represent 'Bill Savings' and *Negative* values represent 'Bill Increase.'

The analysis reveals that the type of space heating has significant influence on the bill impact for the TOU participants. While TOU participants with all space heating types experienced significant increases in bills during Winter season, they achieved significant bill savings during non-Winter, which are statistically significant. Overall, all space heating types exhibit significant annual bill savings ranging from $120 to $164. Notably, TOU participants with electrified space heating exhibit an average annual bill savings of $153, refer to Table 19. While TOU participants who switched heating types show a change in electric costs, this analysis does not account for additional fuel costs or fuel savings for non-electric heating sources they may have incurred.

[8] TOU rates were 32.12 ¢/kWh during peak hours and 16.931 ¢/kWh during off-peak hours.

Table 19: Change in Daily Electricity Bill by Space Heating Type for All Cohorts of Residential TOU Participants

Parameters	De-Electrified	Electrified	Steady Electric	Steady Non-Electric
Winter				
Avg. Bill Savings ($/day)[a]	-1.12 ± 0.02	-1.49 ± 0.02	-1.61 ± 0.01	- 0.76 ± 0.01
Avg. Bill – Residential TOU, Pre-Pilot ($/day)	7.3	5.2	10.3	3.8
Relative Avg. Bill Savings (%)[a]	-15.4%	-28.5%	-15.6%	-19.4%
Significance (p_Value≤0.05)	✓	✓	✓	✓
Non-Winter				
Avg. Bill Savings ($/day) [a]	1.56 ± 0.02	1.37 ± 0.01	1.71 ± 0.01	1.22 ± 0.01
Avg. Bill – Residential TOU, Pre-Pilot ($/day)	4.6	4.2	5.3	4.0
Relative Avg. Bill Savings (%)[a]	34.3%	32.9%	32.5%	30.5%
Significance (p_Value≤0.05)	✓	✓	✓	✓
Annual				
Avg. Bill Savings ($/day)[a]	0.45 ± 0.02	0.42 ± 0.01	0.33 ± 0.01	0.38 ± 0.01
Avg. Bill – Residential TOU, Pre-Pilot ($/day)	5.6	4.3	7.4	3.9
Relative Avg. Bill Savings (%)[a]	8.0%	9.9%	4.5%	9.5%
Significance (p_Value≤0.05)	✓	✓	✓	✓

[a] Positive values represent 'Bill Savings' and Negative values represent 'Bill Increase.'

3.2.2 Price Elasticity

Residential TOU participants' responsivity to electricity prices ($/kWh) was evaluated by estimating daily price elasticity during non-holiday weekdays in Winter season, as well as the Inter-period Substitution Price Elasticity during Winter season. Daily Price Elasticity reflects the change in overall daily electricity usage caused by changes in the average daily price ($) per kWh. It is expressed as the percent (%) change in the average electricity usage associated with a 1% increase in the daily average energy price. Inter-period Substitution Price elasticity reflects the participants' ability to substitute more expensive electricity usage during TOU peak hours with less expensive off-peak hours. It is expressed as the percent (%) change in the ratio of peak-to-off-peak average load associated with a 1% increase in the peak-to-off-peak price ratio.

The analysis reveals a daily price elasticity of -1.05 (± 0.1) during non-holiday weekdays in Winter, implying that for 1% increase in the average daily electricity price per kWh, the average daily electricity usage decreases by 1.05% during non-holiday weekdays in Winter. The inter-period substitution elasticity is estimated at -0.14 (± 0.001), indicating that a 1% increase in the ratio of peak-to-off-peak rates can lead to a decrease of 0.14% in the peak-to-off-peak load ratio by the residential TOU customers, which is statistically significant.

4 Residential CPP Tariff Impacts

This section presents the analysis results for load and economic impacts of the Domestic CPP Tariff for all cohorts in Phase 4. The goal of the residential CPP pilot is to encourage customers to shift their electricity usage during CPP events to the non-event periods when system utilization is lower, thereby providing DR capacity. This is done by presenting customers with options to lower their energy bills if they participate in load shifting. The price differential is derived from system savings created in the near-term in the form of reduced fuel and purchased power costs, and over the longer-term in the form of avoided generation, transmission and distribution infrastructure costs.

The impacts of CPP Tariff and the 14 events during Phase 4 (April 1, 2024 to March 31, 2025) are evaluated within this section. Table 20 presents the CPP events along with the Starting and Ending times, average outdoor temperature, and the weekday status.

Table 20: List of CPP Events and Their Corresponding Starting/Ending Times, Average Outdoor Temperature, and Weekday Status

Event Number	Event Date	Event Start Time (Hour)	Event End Time (Hour)	Average Outdoor Temperature (°C)[c]	Weekday Status[a]
1	2024-12-04	17:00	21:00	-3.6	NHW
2	2024-12-15	17:00	21:00	-2.5	Weekend
3	2024-12-20	7:00	11:00	-2.9	NHW
4	2024-12-22	17:00	21:00	-9.5	Weekend
5[b]	2024-12-23	7:00	11:00	-9.0	NHW
6[b]	2024-12-23	17:00	21:00	-9.0	NHW
7	2025-01-21	17:00	21:00	-9.1	NHW
8	2025-01-22	7:00	11:00	-13.1	NHW
9	2025-02-02	17:00	21:00	-9.9	Weekend
10	2025-02-05	17:00	21:00	-12.2	NHW
11	2025-02-06	7:00	11:00	-11.0	NHW
12	2025-03-04	7:00	11:00	-7.8	NHW
13	2025-03-10	7:00	11:00	-2.5	NHW
14	2025-03-11	7:00	11:00	-3.9	NHW

[a] NHW: Non-Holiday Weekdays.

[b] Double events in the same day.

[c] Average temperature of all events was -7.6 °C

Table 21 below summarizes the characteristics of the residential CPP participants that were included in the analysis of the load and economic impacts. As seen in Table 5, the number of CPP participants in Cohort 4 is much larger than that in Cohort 1, Cohort 2 and Cohort 3.

Table 21: Summary of Residential CPP Sample Size[9]

Parameters	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Sample Size	161	75	468	1,606	2,310
Heating Type:					
Steady Electric	75%	79%	60%	62%	63%
Steady Non-Electric	9%	8%	23%	23%	21%
Electrified	12%	5%	11%	10%	10%
De-Electrified	4%	8%	6%	5%	6%
Region:					
Greater Halifax	73%	70%	57%	60%	59%
Rest of Nova Scotia	27%	30%	43%	40%	41%

4.1 Load & Usage Impacts

This section presents and discusses the electrical load impact from the Domestic CPP Tariff.

4.1.1 Change in Load during Peak Periods

Table 22 summarizes the results of the analysis for morning and evening CPP events for each cohort and all participants combined. The average load reduction metrics are presented along with their MoE at a confidence level of 90%. While all cohorts exhibit statistically significant load reduction during morning and evening CPP events, the results from cohort 4 show lower MoE 90% due to the higher number of participants in that cohort. The smaller MoE indicates the improved reliability of the results for load reductions. Overall, CPP participants demonstrated load reductions of 0.61 kW and 0.77 kW, corresponding to 25.4% and 28.5% relative load reductions, during morning and evening CPP events in Phase 4, respectively. The overall average load reduction across all residential CPP participants and events is 0.69 kW.

[9] Sample size in this table differs from the participation summary found in Table 5 as some participants are removed due to not meeting AMI data criteria necessary for the regression analysis (refer to cleaning steps in Table 69).

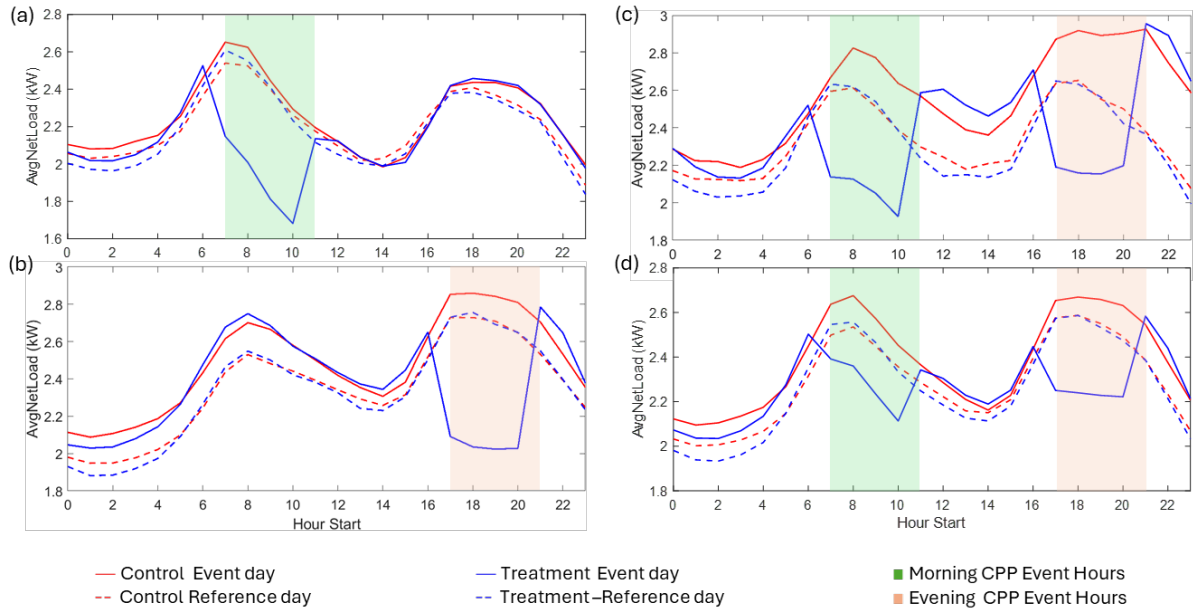
Table 22: Change in Load during CPP Events for Residential CPP Participants

Parameters	Morning Events					Evening Events				
	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Avg. Load Reduction [a] (kW)	0.68 ± 0.10	1.22 ± 0.16	0.62 ± 0.06	0.60 ± 0.03	0.61± 0.03	0.85 ± 0.10	1.60 ± 0.60	0.88 ± 0.06	0.70 ± 0.03	0.77± 0.03
Avg. Load – Residential CPP Participants, Pre-Pilot (kW)	2.8	3.3	2.6	2.4	2.5	2.9	3.5	2.8	2.6	2.7
Relative Avg. Load Reduction[a] (%)	24.3%	36.9%	23.8%	23.9%	25.4%	29.3%	46.7%	31.5%	26.9%	28.5%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

Figure 22 illustrates the daily load profile for residential CPP participants as well as the control group during event day and reference day with morning events only, evening events only, both morning and evening events, and for all event days combined. The residential CPP participants exhibit significant load shifts during morning, evening as well as double event periods, compared to reference days.

Figure 22: Load Shapes for Residential CPP Participants on Event Days (a) with Morning Only Events, (b) with Evening Only Events, (c) with Double-Event, and (d) for All Event Days



Change in Load by Space Heating Classes During Peak Events

Table 23 summarizes the average load reductions during morning and evening events for space heating classes of all cohorts combined in Phase 4. It is important to note that, since load reductions are calculated by comparing event and reference days during the 2024/25 Winter, the change in space heating type between the baseline and the pilot period does not directly impact load reduction results in the DiD analysis.

Table 23: Change in Load during CPP Events by Heating Class for Residential CPP Participants

Parameters	Morning				Evening			
	De-Electrified	Electrified	Steady Electric	Steady Non-Electric	De-Electrified	Electrified	Steady Electric	Steady Non-Electric
Avg. Load Reduction [a] (kW)	0.57 ± 0.10	0.66 ± 0.08	0.74 ± 0.03	0.18 ± 0.02	0.74 ± 0.10	0.83 ± 0.08	0.92 ± 0.03	0.30 ± 0.03
Avg. Load – Residential CPP Participants, Pre-Pilot (kW)	2.4	2.4	3.1	0.8	2.0	2.6	3.3	1.2
Relative Avg. Load Reduction[a] (%)	27.6%	32.4%	24.0%	22.0%	36.9%	31.7%	28.2%	26.0%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

Change in Load per Critical Peak Event

Figure 23a illustrates the average load reduction (kW) per CPP event date for all Phase 4 cohorts, along the corresponding event-average outdoor temperature (°C). The residential CPP participants exhibit significant load reduction across all event days. Three events which occurred during weekends are marked as H/W. The CPP participants exhibit an average load reduction of 0.76 kW during the weekends, which is comparable to the average load reduction of 0.67 kW during all non-holiday weekdays.

Figure 23b presents the disaggregated average load reduction by morning and evening events on CPP event days. Overall, CPP participants exhibit higher average load reductions during evening events than morning events. Notably, CPP participants achieved the largest average load reduction of 0.9 kW during the evening event on February 05, 2025, when the temperature was -12 °C. In contrast, the participants demonstrated the smallest load reduction of 0.46 kW on March 10, 2025 when the temperature was -3 °C. Refer to Section 4.1.5 for the effect of temperature on CPP load reduction.

Figure 23: (a) Average Load Reduction (kW) per CPP Event along with Average Event Temperature (°C), and (b) Average Load Reduction per CPP Event Date by Morning, Evening, or Morning and Evening CPP Event

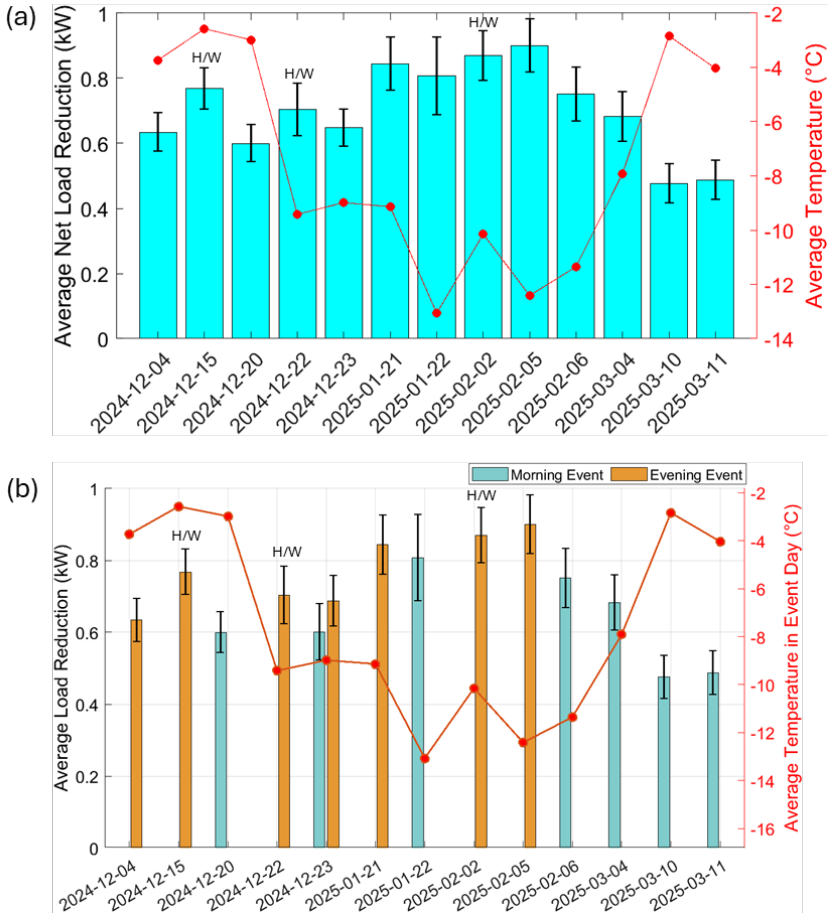


Figure 24 depicts the variations in the average hourly load reduction during each peak event. The trend for most events is that load reduction improves from the first to the second hour, on average is sustained from the second to the third hour and tapers off from the third to the fourth hour.

Figure 24: Average Hourly Load Reduction for CPP Event Change in Load by Region, Income Level, and Residents per Household

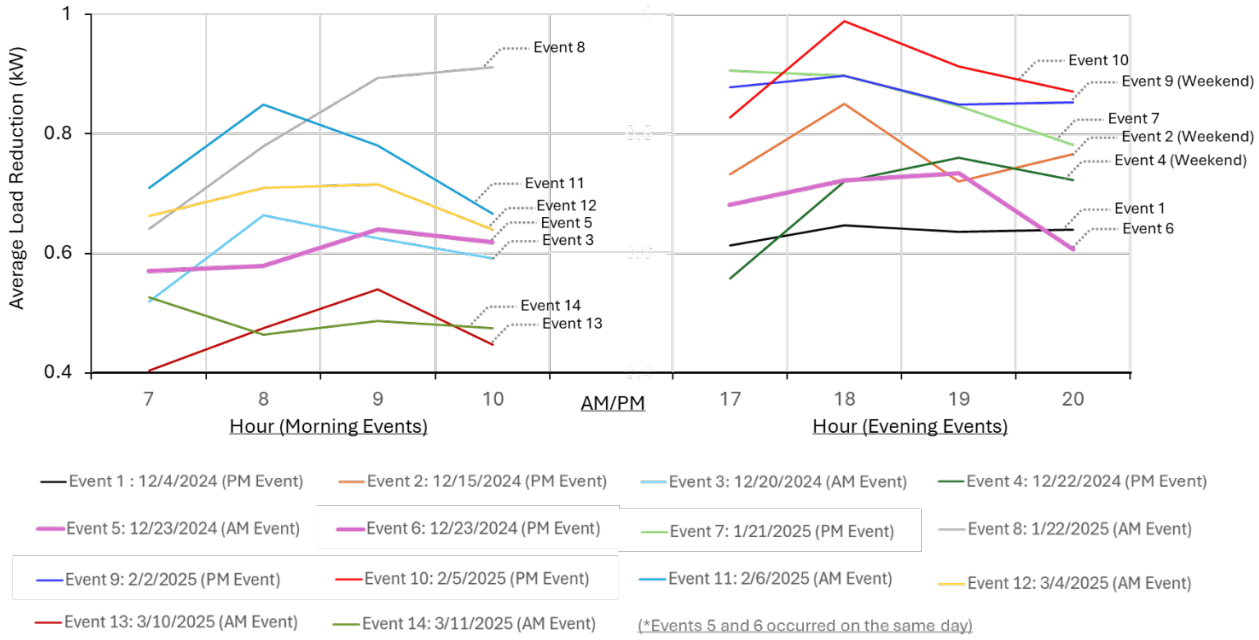


Figure 25 depicts the average load reduction achieved by CPP participants according to the region of premises in Nova Scotia, where CPP customers located in Halifax Area exhibit a statistically significant higher load reduction compared to those in the rest of Nova Scotia.

Figure 25: Average Load Reduction during Morning and Evening CPP Events for Residential CPP Participants Located in the Greater Halifax Area and the Rest of Nova Scotia

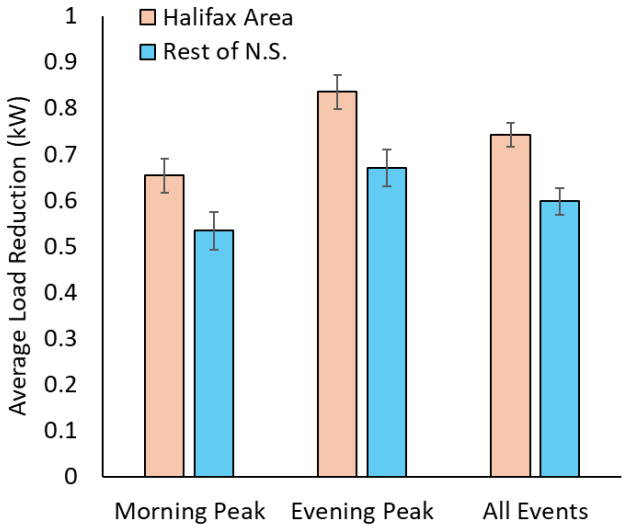
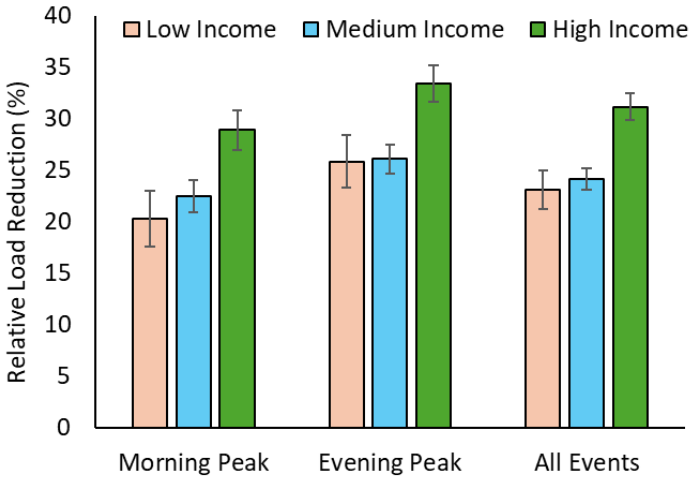


Figure 26 illustrates the average load reduction by CPP participants by income level (low-, medium- and high-income levels).

Figure 26: Relative Average Load Reduction (%) by Income Levels of Residential CPP Participants during Morning and Evening Events as well as Overall across All Peak Periods



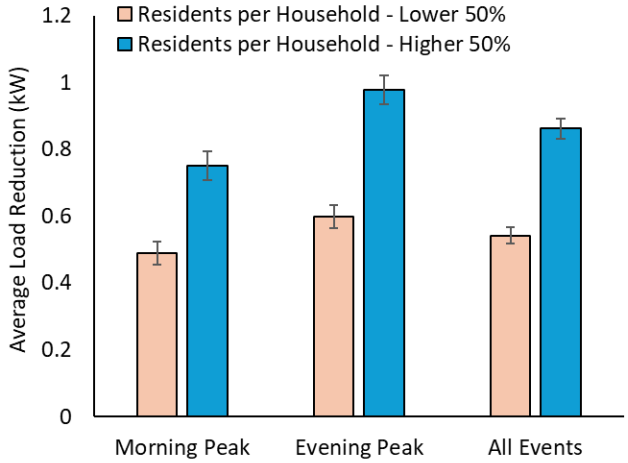
CPP customers with higher income levels achieved a higher relative load reduction of 31% overall, corresponding to 0.88 kW (Table 24), compared to CPP participants with low- and medium-income levels that demonstrated relative load reductions of 23% and 24%, respectively.

Table 24: Change in Load during CPP Events by Income Level for Residential CPP Participants

Parameters	Low-Income			Medium-Income			High-Income		
	AM Event	PM Event	Overall	AM Event	PM Event	Overall	AM Event	PM Event	Overall
Avg. Load Reduction [a] (kW)	0.43 ± 0.06	0.61 ± 0.06	0.52 ± 0.04	0.55 ± 0.04	0.69 ± 0.04	0.62 ± 0.03	0.78 ± 0.05	1.01 ± 0.05	0.88 ± 0.04
Avg. Load – Residential CPP Participants, Pre-Pilot (kW)	2.1	2.4	2.2	2.5	2.6	2.6	2.7	3.0	2.8
Relative Avg. Load Reduction[a] (%)	20%	26%	23%	22.5%	26%	24%	29%	33%	31%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓	✓	✓	✓
[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'									

Figure 27 illustrates the load reduction by CPP participants according to Residents per Household, segmented at the Lower 50% and Higher 50% for the comparison. The households with more residents achieved an overall load reduction of 0.87 kW which is greater than 0.54 kW achieved by the lower 50% households. It is worth noting the average household size difference between these segments, 1.99 residents in the lower 50% and 2.79 residents in the higher 50%.

Figure 27: Average Load Reduction (kW) by Residents-per-Household (lower 50% vs. higher 50%) for Morning and Evening CPP Event Hours as well as All Event Hours



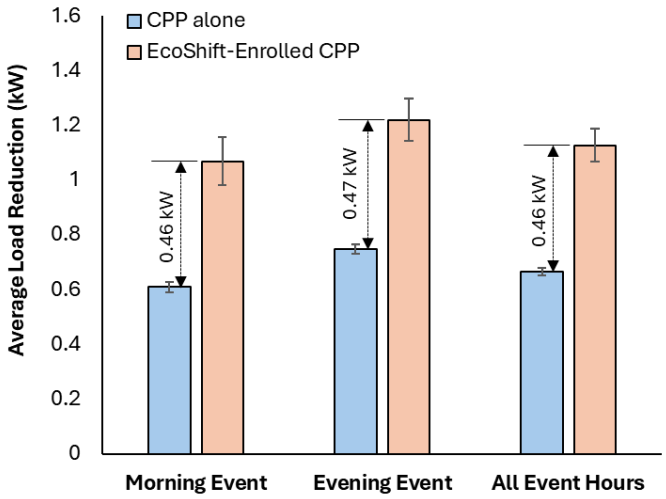
Change in Load with Eco Shift

E1's Eco Shift is a DR initiative offered separately from TVP and was implemented within subset of the TVP treatment participants who opted into both programs. It is designed to encourage load reduction during peak hours by connecting with smart devices that can automatically reduce electricity usage during peak demand periods. Refer to Attachment III: Methodology (Table 71) for a list of Eco Shift events.

NS Power evaluated the incremental load reduction due to Eco Shift compared to non-Eco Shift residential CPP customers during CPP event hours relative to reference days. NS Power used a triple-difference (DDD) regression analysis to estimate the incremental effect of Eco Shift on CPP impact, refer to equation (8). The analysis reveals that those CPP participants that enrolled in Eco Shift reduced their overall load by an additional 0.46 ± 0.05 kW during all CPP peak hours, where they reduced their load by additional 0.46 ± 0.07 kW and 0.47 ± 0.061 kW during morning and evening CPP hours, respectively (Figure 28). Also, the analysis shows that the CPP program alone led to an overall load reduction of 0.67 ± 0.013 kW, indicating that the CPP customers enrolled in Eco Shift program reduced their load by approximately 1.13 kW (Figure 28), combining both CPP and the incremental Eco Shift effect.

In conclusion, the Eco Shift program provides a statistically significant effect on enhancing load reduction among those CPP participants that also enrolled in the Eco Shift program.

Figure 28: Load Reductions for Residential CPP Participants vs. Eco Shift-Enrolled Residential CPP Participants during Combined Event (CPP + Eco Shift) Morning and Evening Event Hours, Reflecting the Eco Shift Additional Load Impact



Notably, due to there being only three CPP events without Eco Shift, occurring only in March, NS Power did not evaluate Eco Shift enrolled CPP customers during non-Eco Shift events as done in TOU.

4.1.2 Snapback Effect

The CPP participants exhibit relatively small but statistically significant snapback effects during morning, evening and double-event snapback periods, indicating significant increase in electricity usage during the four hours immediately following peak events. CPP participants experienced a snapback of 0.15 kW during the double-snapback periods, which is significantly greater than the snapback during only morning or evening snapbacks (Table 25).

Table 25: Snapback Effect for Residential CPP Participants

Parameters	Average Load Reduction [a] (kW)	Significance (p_Value≤0.05)
Morning Snapback	-0.04 ± 0.02	✓
Evening Snapback	-0.08 ± 0.03	✓
Double-Event Snapback[b]	-0.15 ± 0.05	✓
Overall Snapback	-0.06 ± 0.02	✓

[a] Positive and Negative values represent 'Reduction' and 'Increase' in electricity usage, respectively.

[b] Applies to the event day(s) with both morning and evening CPP peak hours.

4.1.3 Change in Load during Highest ANL Hours

Figure 29 illustrates the distribution of Top 20, 50 and 88 highest ANL hours for residential CPP participants during weekdays and weekends as well as across CPP events. The majority of the highest ANL hours occurred on weekdays. Specifically, 55%, 36% and 27% coincided with the top 20, 50, and 88 ANL hours, respectively, take place during peak periods (Figure 29). In addition,

approximately 40%, 28% and 21% of all CPP events, which coincided with the top 20, 50 and 88 ANL hours, respectively, occurred during weekdays, while only 15%, 8% and 6% of CPP events, which coincide with top 20, 50 and 88 ANL hours, took place on Weekends.

Figure 29: Distribution of Top 20, Top 50 and Top 88 ANL Hours by Day Type (Weekday / Weekend) and Residential CPP Events

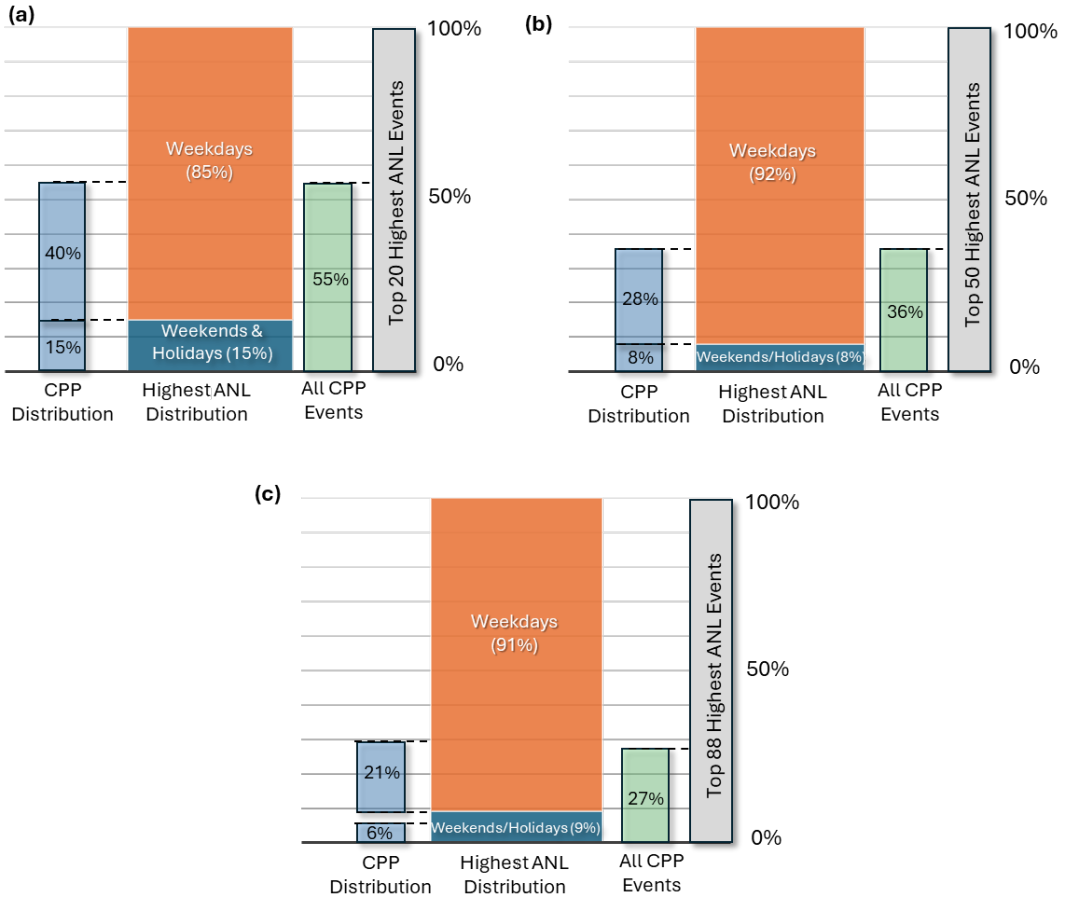


Table 26 summarizes the estimated changes in load for residential CPP participants during the highest ANL hours. Results indicate that participants achieved statistically significant load reductions during the top 20, 50, and 88 highest ANL hours. Focusing specifically on ANL hours that coincide with CPP peak periods, the CPP participants demonstrate slightly higher average load reductions during the top 20, 50 and 88 ANL hours compared to the corresponding highest ANL hours overall.

Table 26: Change in Load (kW) during Highest Winter ANL Hours for Residential CPP Participants

Parameters	Highest ANL Hours			ANL Hours Coincide with CPP Events		
	Top 20	Top 50	Top 88	Top 20	Top 50	Top 88
Avg. Load Reduction [a] (kW)	0.75 ± 0.07	0.63 ± 0.06	0.55 ± 0.04	0.85 ± 0.07	0.84 ± 0.06	0.80 ± 0.05
Avg. Load – CPP Participants, Pre-Pilot (kW)	2.9	2.9	2.8	2.9	2.9	2.9
Relative Avg. Load Reduction [a] (%)	26%	23%	19%	29%	28.5%	28%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

4.1.4 Change in Usage

The change in daily usage levels was evaluated through two analyses. For the first analysis, the daily usage reduction during event days was estimated, when at least one CPP event occurred, compared to reference days. For the second analysis, the daily electricity usage levels for Winter and non-Winter days during the treatment period were evaluated compared to the pre-pilot period. Furthermore, both analyses were applied to estimate daily electricity usage changes for different heating classes.

The first analysis found out that for all event days combined, CPP participants reduced their daily electricity usage by an average of 1.7 kWh (± 1.3 kWh) compared to reference days, which is statistically significant. When disaggregated by cohort, the daily usage reductions by cohorts 1-3 were not statistically significant (Table 27). In contrast, cohort 4 exhibits a significant reduction of 1.6 kWh (± 1.5 kWh). When evaluated for different heating classes, the daily usage reduction was not statistically significant for any of the heating-class segments during CPP events compared to reference days.

Table 27: Change in Daily Electricity Usage (kWh/day) by Cohort during CPP Events for Residential CPP Participants

Parameters	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Avg. Usage Reduction (kWh/day)[a]	1.6 ± 4.0	3.1 ± 6.7	1.6 ± 2.9	1.6 ± 1.5	1.7 ± 1.3
Avg. Usage – Residential CPP Participants, Pre-Pilot (kWh/day)	61	71	55	52	54
Relative Avg. Usage Reduction (%)[a]	2.7%	4.3%	2.9%	3.1%	3.1%
Significance (p_Value≤0.05)	X	X	X	✓	✓

[a] Positive values represent 'Usage Reduction' and Negative values represent 'Usage Increase.'

The results of the second analysis are summarized in Table 28 and show changes in daily electricity usage level for cohorts 1 to 4 and all cohorts combined during non-holiday weekdays and holiday weekends in Winter as well as non-Winter days. All cohorts significantly reduced their daily usage during non-holiday weekdays in Winter. All cohorts exhibit load reductions during weekends

holidays in Winter, although the load reduction in cohort 3 is not statistically significant. Due to the lack of data for non-Winter days in cohort 4, evaluation of the daily usage reduction during non-Winter days was not completed. For all cohorts of CPP participants combined, the annually aggregated usage level reductions are estimated at 0.973 ±0.24 kWh per day, which add up to 355 kWh per year on average and are statistically significant.

Table 28: Change in Daily Electricity Usage (kWh/day) by Cohort for Residential CPP Participants

Parameters	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Winter, Non-Holiday Weekdays					
Avg. Usage Reduction (kWh/day)[a]	3.0 ± 1.4	3.1 ± 2.0	1.0 ± 0.9	1.1 ± 0.5	1.2 ± 0.4
Avg. Usage – Residential CPP Participants, Pre-Pilot (kWh/day)	50.7	60.5	44.0	43.5	44.5
Relative Usage Reduction (%)[a]	6.0%	5.1%	2.3%	2.5%	2.7%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓
Winter, Weekends / Holidays					
Avg. Usage Reduction (kWh/day)[a]	2.3 ± 1.7	4.0 ± 2.5	0.9 ± 1.1	0.9 ± 0.6	1.0 ± 0.5
Avg. Usage – Residential CPP Participants, Pre-Pilot (kWh/day)	51.0	62.0	45.8	44.6	45.7
Relative Usage Reduction (%)[a]	4.6%	6.5%	1.8%	2.1%	2.3%
Significance (p_Value≤0.05)	✓	✓	X	✓	✓
Non-Winter Days					
Avg. Usage Reduction (kWh/day)[a]	1.9 ± 0.5	-0.3 ± 1.0	-0.1 ± 0.3	n/a	0.5 ± 0.3
Avg. Usage – Residential CPP Participants, Pre-Pilot (kWh/day)	28.4	30.2	25.6		26.7
Relative Usage Reduction (%)[a]	6.8%	-1.0%	-0.5%		2.0%
Significance (p_Value≤0.05)	✓	X	X		✓

[a] Positive values represent 'Usage Reduction' and Negative values represent 'Usage Increase.'

Table 29 presents changes in daily electricity usage level by space heating for all cohorts of residential CPP participants during pilot period compared to pre-pilot period. During non-holiday weekdays in Winter, CPP participants with electrified space heating exhibited a statistically significant increase in daily usage level by 13%, corresponding to a daily usage increase of 3.84 kWh. In contrast, de-electrified and steady electric participants demonstrated significant daily usage reductions of 1.31 kWh and 2.01 kWh, respectively. Steady non-electric participants exhibit statistically insignificant changes in daily electricity usage level during non-holiday weekdays.

Table 29: Change in Daily Electricity Usage Level by Space Heating Type for All Cohorts of Residential CPP Participants

Parameters	De-Electrified	Electrified	Steady Electric	Steady Non-Electric
Winter, Non-Holiday Weekdays				
Avg. Usage Reduction (kWh/day)[a]	1.31 ± 1.08	-3.84 ± 0.81	2.02 ± 0.45	0.15 ± 0.33
Avg. Usage – Residential CPP Participants, Pre-Pilot (kWh/day)	42.0	29.6	55.6	18.7
Relative Avg. Usage Reduction (%)[a]	3.1%	-13.0%	3.6%	0.8%
Significance (p_Value≤0.05)	✓	✓	✓	X
Winter, Weekends / Holidays				
Avg. Usage Reduction (kWh/day)[a]	0.71 ± 1.42	-4.39 ± 1.04	1.99 ± 0.56	-0.09 ± 0.4
Avg. Usage – Residential CPP Participants, Pre-Pilot (kWh/day)	42.8	30.8	56.9	19.5
Relative Avg. Usage Reduction (%)[a]	1.7%	-14.3%	3.5%	-0.5%
Significance (p_Value≤0.05)	X	✓	✓	X
Non-Winter Days				
Avg. Usage Reduction (kWh/day)[a]	0.14 ± 1.72	-0.97± 0.67	0.50 ± 0.34	0.41 ± 0.49
Avg. Usage – Residential CPP Participants, Pre-Pilot (kWh/day)	26.7	21.7	29.7	18.9
Relative Avg. Usage Reduction (%)[a]	0.5%	-4.4%	1.7%	2.1%
Significance (p_Value≤0.05)	X	✓	✓	X

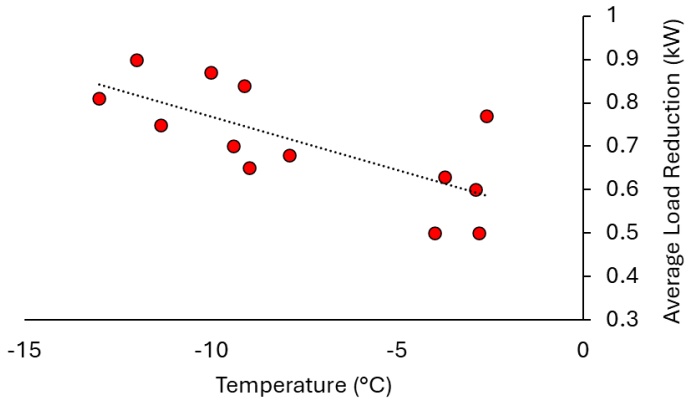
[a] Positive values represent 'Usage Reduction' and *Negative* values represent 'Usage Increase'.

As seen in Table 29, during weekends / holidays in Winter, CPP customers with electrified heating systems increased their daily usage levels by 14.3%, corresponding to 4.39 kWh, which is statistically significant. In contrast, participants with steady electric heating systems achieved daily usage reductions of 3.5%, corresponding to statistically significant electricity usage reduction of 1.99 kWh during weekends / holidays. CPP customers with de-electrified or steady non-electric heating systems demonstrated insignificant changes in daily usage level during weekends / holidays in Winter.

4.1.5 Effect of Weather (Temperature) on Load Reduction

The DiD analysis reveals that the average load reduction is increased by 0.019 kW (± 0.003 kW) per 1 °C decrease in outdoor temperature, implying that CPP customers increase load reduction when the weather becomes colder. Figure 30 illustrates the correlation between average load reduction (kW) and average outdoor temperature during CPP event days, where the upward trend with respect to colder temperature indicates an increasing load reduction when the outdoor temperature decreases.

Figure 30: The Correlation of Load Reduction by Residential CPP Participants with Outdoor Temperature



4.1.6 Effect of Consecutive CPP Events on Load Reduction

During Phase 4, like Phase 3, there was only one instance of two consecutive CPP events, which occurred when events 5 and 6 took place on December 23, 2024. The second of these consecutive events (event 6) led to a slightly higher load reduction, but not statistically different, compared to its preceding event (event 5). This suggests that being preceded by another CPP event did not negatively affect the load reduction by CPP residential customers during this event. However, because Phase 4 includes only a single occurrence of consecutive events, the available data is insufficient to draw broader conclusions the overall impact of consecutive CPP events. The individual event load impacts are displayed in Figure 23.

4.2 Economic Impacts

This section presents and discusses the impact of residential CPP tariffs on the electricity bill as well as price elasticity.

4.2.1 Change in Electricity Bills

Table 30 summarizes the applicable tariffs used for residential CPP impact on billing. Tariff details can be found in Attachment I: Riders and Tariff Structure.

Table 30: Tariffs Used for Analyzing Residential CPP Impact on Electricity Bill

Customer Type and Period	Applicable Tariff
Control, Reference Day	Domestic Standard Tariff
Control, during Pilot	Domestic Standard Tariff
Treatment, Reference Day	Domestic Standard Tariff
Treatment, during Pilot	Domestic CPP Tariff

Table 31 presents the bill impact for residential CPP, where participants exhibit an overall annual average bill saving of $0.57 per day, corresponding to 8.6% of average annual bill. This amount of

annual bill saving is statistically significant. The residential CPP participants achieved an average bill saving of $0.75 per day during non-Winter days, corresponding to 15.0% of average non-Winter bill. The non-Winter days savings are primarily due to a reduced rate per kWh during the non-Winter days (14.222¢/kWh under CPP Tariff compared to 16.931¢/kWh for domestic tariffs). Furthermore, the CPP participants achieved an overall bill saving of $0.37 per day during Winter. Also, the participants experienced the highest bill saving of $0.80 during weekends/holidays in Winter. Notably, participants experienced bill savings of $0.14 per day during non-holiday/weekdays when the majority of CPP events occurred. This lower bill saving is attributed to the fact that tariffs during CPP peak hours (169.31 ¢/kWh) are approximately twelve times higher than the Tariff during non-event hours (14.222 ¢/kWh).

Table 31: Change in Daily Electricity Bill for All Cohorts of Residential CPP Participants

Parameters	Winter Non-Holiday Weekdays	Winter Holiday/ Weekends	Winter Overall	Non-Winter Days	Annual Average
Avg. Bill Savings ($/day)[a]	0.14 ± 0.01	0.80 ± 0.02	0.37 ± 0.01	0.75± 0.01	0.57 ± 0.01
Avg. Bill – Residential CPP Participants, Pre-Pilot ($/day)	8.4	8.6	8.5	5.0	6.5
Relative Avg. Bill Savings (%)[a]	1.7%	9.3%	4.4%	15.0%	8.6%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓

[a] Positive values represent 'Bill Savings' and *Negative* values represent 'Bill Increase.'

The analysis reveals that the type of space heating has a significant effect on the bill savings for the CPP participants. The steady electric participants achieved the highest bill savings compared to steady non-electric. While CPP participants who switched heating types show a change in electric costs, this analysis does not account for additional fuel costs or fuel savings for non-electric heating sources they may have incurred. All space heating classes experienced the most bill savings during non-Winter days, among which the participants with steady electric heating systems achieved the highest bill savings of $0.86 per day. Overall, except for electrified CPP participants, other space heating types achieved statistically significant annual bill savings ranging from $153 to $248 per year. While electrified customers achieved a bill savings of $101 during non-Winter season, they did not experience statistically significant annual bill savings.

Table 32: Change in Daily Electricity Bill by Space Heating Type for All Cohorts of Residential CPP Participants

Parameters	De-Electrified	Electrified	Steady Electric	Steady Non-Electric
Winter				
Avg. Bill Savings ($/day)[a]	0.36 ± 0.04	-0.47 ± 0.03	0.56 ± 0.02	0.14 ± 0.01
Avg. Bill – Residential CPP, Pre-Pilot ($/day)	6.3	8.0	10.3	3.4
Relative Avg. Bill Savings (%)[a]	5.8%	-5.9%	5.4%	4.1%
Significance (p_Value≤0.05)	✓	✓	✓	✓
Non-Winter				
Avg. Bill Savings ($/day)[a]	0.70 ±0.04	0.47 ± 0.02	0.86 ± 0.01	0.57 ± 0.02
Avg. Bill – Residential CPP, Pre-Pilot ($/day)	4.4	3.7	4.7	3.0
Relative Avg. Bill Savings (%)[a]	15.9%	12.5%	18.3%	18.8%
Significance (p_Value≤0.05)	✓	✓	✓	✓
Annual				
Avg. Bill Savings ($/day)[a]	0.44 ± 0.03	0.02 ± 0.03	0.68 ± 0.01	0.42 ± 0.04
Avg. Bill – Residential CPP, Pre-Pilot ($/day)	5.4	5.4	7.3	3.3
Relative Avg. Bill Savings (%)[a]	8.1%	0.3%	9.4%	12.7%
Significance (p_Value≤0.05)	✓	X	✓	✓

[a] Positive values represent 'Bill Savings' and *Negative* values represent 'Bill Increase.'

4.2.2 Price Elasticity

Price elasticity was evaluated to measure residential CPP participants' responsivity to electricity prices during Phase 4. Specifically, NS Power evaluated Daily Price Elasticity during Winter season and annual overall, as well as the Inter-period Substitution Price Elasticity during Winter season.

For clarification, Daily Price Elasticity reflects the change in overall daily electricity usage caused by changes in the average daily price ($) per kWh. It is expressed as the percent (%) change in the average electricity usage associated with a 1% increase in the daily average energy price. Inter-period Substitution Price elasticity reflects the participants' ability to substitute more expensive electricity usage during CPP events with less expensive off-peak loads, and estimates changes in load shapes caused by a change in the peak-to-off-peak price ratio. It is expressed as the percent (%) change in the ratio of peak-to-off-peak average load associated with a 1% increase in the peak-to-off-peak price ratio.

The analysis reveals Daily Price Elasticity of -0.2 (± 0.06) during Winter season, indicating that for 1% increase in the average daily price per kWh, the average daily electricity usage decreases by 0.2% during Winter. Furthermore, the inter-period substitution elasticity is estimated at -0.19 (± 0.004), indicating that a 1% increase in the ratio of peak-to-off-peak rates can lead to a decrease of 0.19% in the peak-to-off-peak load ratio by the residential CPP customers, which is statistically significant.

5 Commercial TOU Tariff Impacts

This section presents and discusses the estimated load and economic impacts of the commercial TOU program. The goal of the commercial TOU pilot is to encourage customers to shift their electricity usage from peak periods to off-peak periods when system utilization is typically lower. This is done by presenting customers with option to lower their energy bills if they participate in load shifting. The price differential is derived from system savings created in the near-term in the form of reduced fuel and purchased power costs, and over the longer-term in the form of avoided generation, transmission and distribution infrastructure costs.

Commercial TOU customer sample size for Phase 4 is currently at 50 participants, most of which enrolled in cohorts 1 – 3 (n = 46) as cohort 4 experienced relatively small enrolment (n=4). A summary of Commercial TOU sample size for the regression is summarized in Table 33.

Table 33: Summary of Commercial TOU Sample Size[10]

Parameter	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Sample Size	19	15	12	4	50
Rate Class					
Small General	9	13	6	4	32
General	10	2	6	0	18
Region					
HRM	12	3	6	3	24
Rest of Nova Scotia	7	12	6	1	26

5.1 Load Impacts

This section presents and discusses the electrical load impact from the commercial TOU pilot.

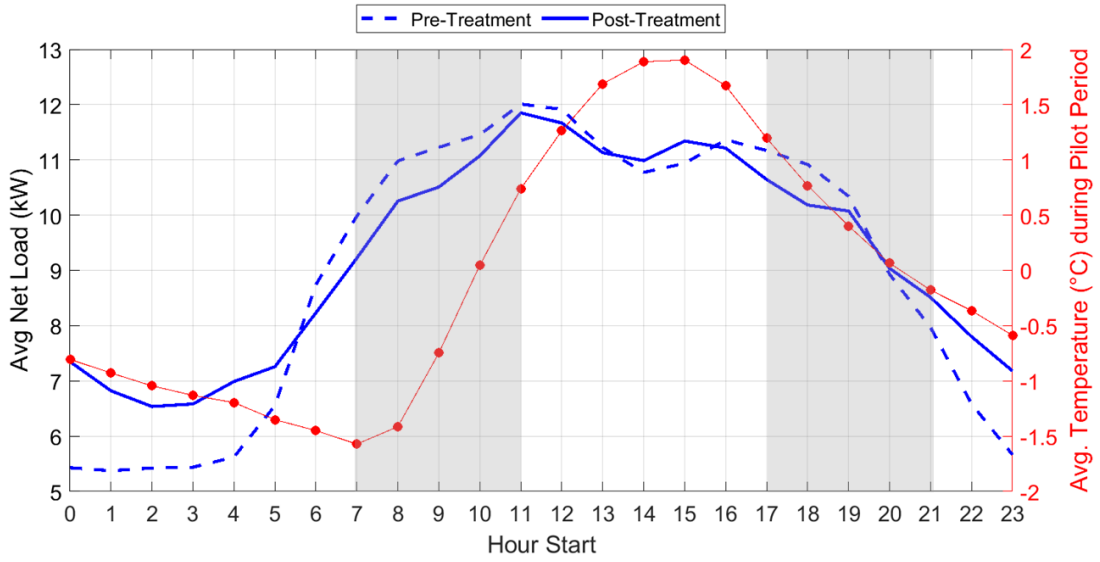
5.1.1 Change in Load during Peak Periods

Figure 31 illustrates the load profiles for commercial TOU participants during the pre-pilot and pilot periods, along with the corresponding variation in outdoor temperature during the pilot period.

Commercial TOU participants exhibit an overall reduction in electricity load during TOU peak hours compared to the pre-pilot period. Notably, during pilot period commercial TOU participants experience a pronounced increase in their load relative to pre-pilot period overnight following evening peak hours and prior to morning peak hours (9:00 PM – 5:00 AM).

[10] Participation in this table differs from the participation summary found in Table 5 as some participants are removed due to not meeting AMI data criteria necessary for the regression analysis. Refer to the seasonal load ratio analysis in equation (13) and cleaning steps in Table 69.

Figure 31: The Hourly-Averaged Load Shapes during Winter Non-Holiday Weekdays for Commercial TOU Participants during Pilot Period and Pre-Pilot Period, and the Variation of Average Outdoor Temperature during Pilot Period with Time (Hour) Corresponding to Commercial TOU Post-Treatment Participants (Highlighted Areas Represent Morning and Evening Peak Hours)



On average, the analysis reveals that commercial TOU participants exhibit an overall peak reduction of 0.8 kW in electricity load, with average load reductions of 6.4%, 8.6%, and 7.4% observed during the morning and evening peaks, and overall for all peak periods, respectively. This estimated effect of commercial TOU is consistent with the difference in load shape during peak hours between pre-pilot and pilot period, as shown in Figure 31.

Table 34 summarizes the results of the Mixed-Effects regression analysis for the morning and evening as well as the overall load impact. Estimated impacts are presented alongside MoE at the 90% confidence level. As shown in Table 34, the estimated impacts of the commercial TOU pilot on average load in overall and during morning and evening peak periods are statistically significant.

Table 34: Change in Load during TOU Peaks for Commercial TOU Participants

Parameters	Morning Peak	Evening Peak	All Peak Hours (Overall)
Avg. Load Reduction (kW)[a]	0.7 ± 0.2	0.9 ± 0.2	0.8 ± 0.1
Avg. Load – Commercial TOU Participants, Pre-Pilot (kW)	10.9	10.3	10.6
Relative Avg. Load Reduction (%)[a]	6.4%	8.6%	7.5%
Significance (p_Value≤0.05)	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

Change in Load during Peak Events by Region

Table 35 presents the average load reduction (kW) by region (Halifax area versus the rest of Nova Scotia) for commercial TOU participants during morning, evening, and all peak hours. Commercial

TOU participants located in the Halifax area exhibit statistically significant load reductions during both morning and evening peak hours with an overall load reduction of 1.4 kW, corresponding to 12% relative load reduction. Likewise, commercial TOU participants in the rest of Nova Scotia exhibit a statistically significant overall load reduction of 0.2 kW across all morning and evening peak hours, although only load reduction during evening peak hours and overall is statistically significant.

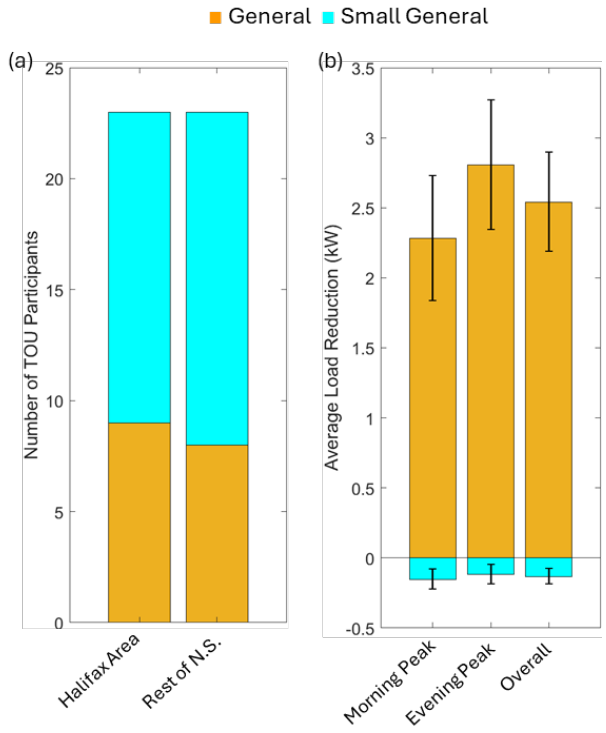
Table 35: Change in Load during TOU Peak Hours by Region for Commercial TOU Participants

Parameters	Halifax Area			Rest of Nova Scotia		
	Morning Peaks	Evening Peaks	All Peak Hours	Morning Peaks	Evening Peaks	All Peak Hours
Avg. Load Reduction (kW)[a]	1.22 ± 0.29	1.49 ± 0.31	1.38 ± 0.20	0.16 ± 0.17	0.24± 0.18	0.20 ± 0.15
Avg. Load – Commercial TOU Participants, Pre-Pilot (kW)	11.9	11.1	11.5	9.9	9.9	9.9
Relative Avg. Load Reduction (%)[a]	10.3%	13.7%	12.0%	1.6%	2.5%	2.1%
Significance (p_Value≤0.05)	✓	✓	✓	X	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

Figure 32a illustrates the distribution of General and Small General commercial TOU participants in the Halifax area compared to the rest of Nova Scotia.

Figure 32: (a) Distribution of Number of General and Small General TOU Participants in Halifax Area and the Rest of Nova Scotia, and (b) the Average Load Reduction (kW) for General and Small General Business Types

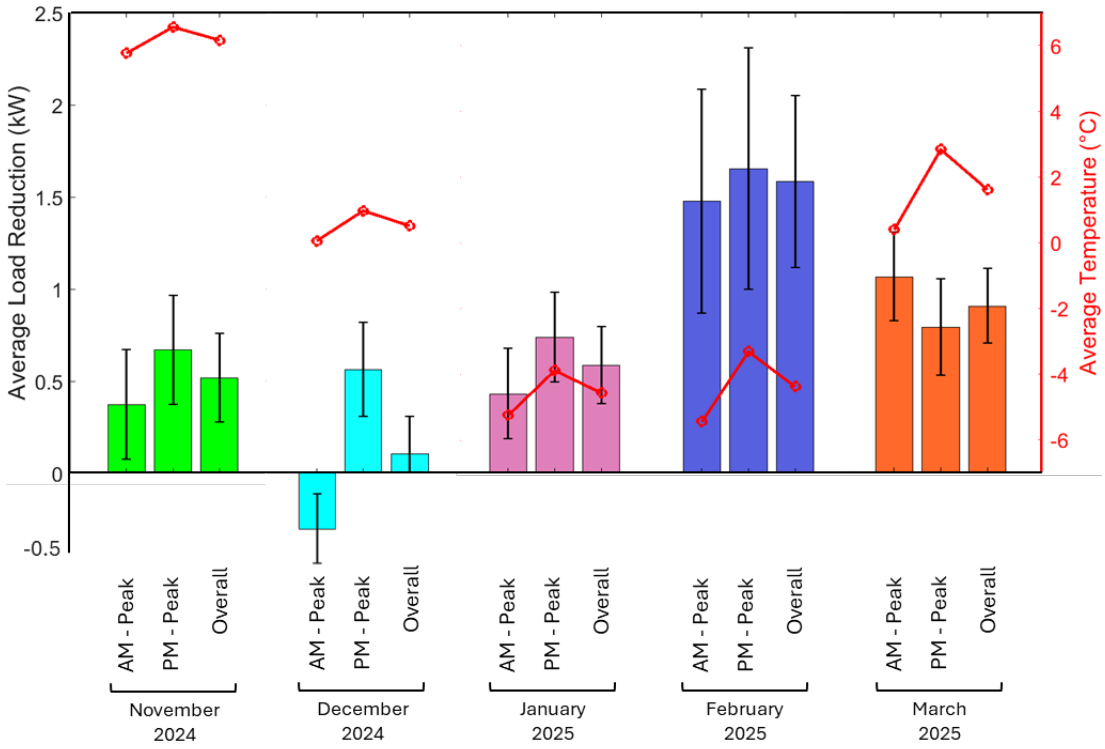


Notably, as shown in Figure 32b, General commercial TOU participants exhibit significant load reductions during both morning and evening peak periods, with an average overall reduction of approximately 2.6 kW. In contrast, Small General TOU participants show load increases during peak hours, with an average increase of approximately 0.22 kW, which is statistically significant although small in magnitude.

Change in Load by Month during Peak Periods

Figure 33 illustrates the impact of commercial TOU in terms of average load reduction (kW), together with the average outdoor temperature (°C) during peak hours by month over the Winter period from November 2024 to March 2025. Except for the morning peak period in December 2024 – which shows a statistically significant load increase – commercial TOU participants demonstrated significant load reductions during both morning and evening peak hours across all Winter months. Notably, in January 2025, when temperatures reached their lowest range (approximately −4 °C to −5.3 °C), participants achieved significant reductions during both morning and evening peak periods. The largest overall load reduction, approximately 1.6 kW, occurred in February 2025, when outdoor temperatures ranged between −3.3 °C and −5.4 °C.

Figure 33: Average Load Reduction (kW) and Temperature Variation during Commercial TOU Peak Periods in Winter for the Months of November, December, January, February, and March



5.1.2 Snapback Effect

NS Power evaluated the snapback effect based on the same method that was applied for load reduction calculation, but specifically for the four hours following the morning and evening peak hours. As summarized in Table 36, commercial TOU participants exhibited a statistically significant load reduction of 0.51 kW during morning snapback hours. In contrast, during evening snapback hours they demonstrated a load increase of 0.9 kW, corresponding to a relative load increase of 13.3%. Although commercial TOU customers showed an overall relative load increase of 1.2% across all snapback periods, this effect was not statistically significant.

Table 36: Snapback Effect for Commercial TOU Participants

Parameters	Avg. Load Reduction [a] (kW)	Relative Avg. Load Reduction [a] (%)	Significance (p_Value≤0.05)
Morning Snapback	0.51 ± 0.19	4.4%	✓
Evening Snapback	-0.90 ± 0.17	-13.3%	✓
Overall Snapback	-0.11 ± 0.17	-1.2%	X

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

5.1.3 Change in Load during Highest ANL Hours

Figure 34 depicts the distribution of Top 20, 50 and 88 highest ANL hours for commercial TOU participants during off-peak, morning peak, evening peak, Weekends and Holidays. As seen in Figure

34a-c, ANL hours occurred disproportionally on weekdays (85% – 92%), exceeding the expected baseline of 5/7 (71%). In addition, more than 70% of the highest ANL hours coincide with the morning and evening peak periods for all distributions of top ANL hours (i.e. 20, 50 and 88). Note that Figure 34 is identical to Figure 20 (Domestic TOU) as the tariffs have the same peak periods.

Figure 34: Distribution of Top 20, Top 50 and Top 88 ANL Hours by Day Type (Weekday / Weekend) and Commercial TOU Period

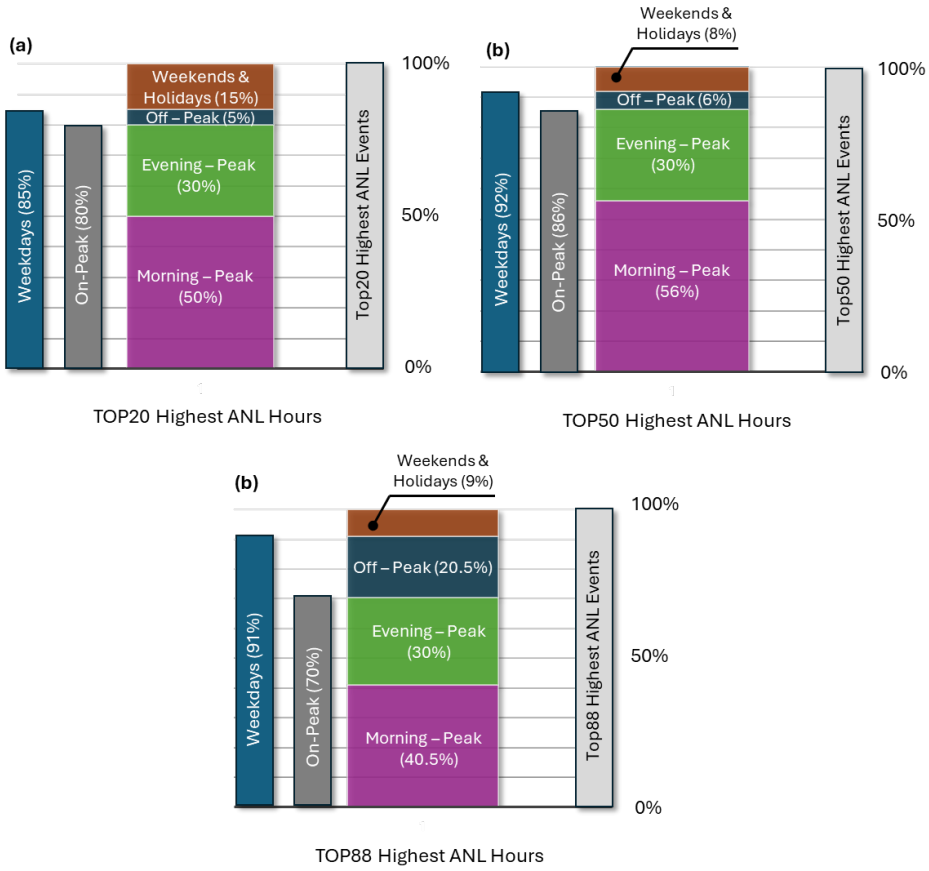


Table 37 summarizes the estimated changes in load during the highest ANL hours overall, as well as during ANL hours that coincide with TOU peak periods. Results indicate that the load increase or reduction by commercial TOU participants was not statistically significant during the top 20, 50, and 88 highest ANL hours. When focusing specifically on ANL hours that coincide with TOU peak periods, the commercial TOU participants exhibit insignificant load increases or decreases during the top 20, 50 and 88 ANL hours compared to the corresponding highest ANL hours overall.

Table 37: Change in Load (kW) during Highest Winter ANL Hours for Commercial TOU Participants

Parameters	Highest ANL Hours			ANL Hours Coincide TOU Peak Periods		
	Top20	Top 50	Top88	Top20	Top 50	Top88
Avg. Load Reduction (kW)[a]	0.06 ± 0.85	0.34 ± 0.50	-0.15 ± 0.44	-0.12 ± 0.84	0.20 ± 0.48	0.10 ± 0.40
Avg. Load Participants, Pre-Pilot (kW)	10.2	9.8	9.0	5.8	7.3	8.2
Relative Avg. Load Reduction (%)[a]	0.5%	3.5%	-1.6%	-2.0%	2.7%	1.2%
Significance (p_Value≤0.05)	X	X	X	X	X	X

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase'

5.1.4 Change in Usage

Changes in daily electricity usage were estimated by applying the same method which was used for estimating hourly load-impact, to daily electricity usage. Table 38 presents the estimated changes in daily electricity usage (kWh/day) for commercial TOU participants.

Table 38: Change in Daily Electricity Usage (kWh/day) for Commercial TOU Participants

Parameters	Annual Average	Winter Overall	Winter – Non-Holiday Weekdays	Winter – Holiday Weekends	Non-Winter
Avg. Usage Reduction (kWh/day)[a]	-15.4 ± 3.9	-9.4 ± 4.0	-3.9 ± 5.1	-19.4 ± 6.5	-22.2 ± 5.7
Avg. Usage – Commercial TOU Participants, Pre-Pilot (kWh/day)	206	194	202	178	216
Relative Usage Reduction (%)[a]	-7.5%	-4.8%	-1.9%	-10.9%	-10.3%
Significance (p_Value≤0.05)	✓	✓	X	✓	✓

[a] Positive and negative values represent 'Usage Reduction' and 'Usage Increase,' respectively.

As shown in Table 38, Commercial TOU participants exhibit a statistically significant increase in daily electricity usage of approximately 15.9 kWh/day on annual average and 19.4 kWh/day during Winter non-holiday weekdays, corresponding to 7.5% and 10.9% increases in daily usage, respectively. In contrast, the commercial TOU participants exhibit a statistically insignificant increase in daily electricity usage during non-holiday weekdays in Winter.

5.2 Economic Impacts

This section presents and discusses the impact of commercial TOU tariffs on the electricity bill as well as price elasticity.

5.2.1 Change in Electricity Bills

The bill impact analysis for the commercial TOU uses the same method that was used for estimating the commercial TOU load impact analysis. In the bill impact analysis, applicable tariffs applied in accordance with the customer type and pilot period, as summarized in Table 39. Note details on these tariffs are included in Attachment I: Riders and Tariff Structure.

Table 39: Tariffs Used for Evaluating the Impact of Commercial TOU on Electricity Bill

Customer Type	Period	Applicable Tariff
Treatment – General	Pre-Pilot	General Tariff – Rate Code 11
Treatment – General	Pilot	General TOU Tariff – Rate Code 83
Treatment – Small General	Pre-Pilot	Small General Tariff – Rate Code 10
Treatment – Small General	Pilot	Small General TOU Tariff – Rate Code 82

Table 40 presents the estimated average changes in daily bill for all cohorts of commercial TOU participants over the Winter season and annual average in Phase 4. The commercial TOU customers experienced an average Bill increase of approximately 12.3 $/day and 3.8 $/day across the Winter and annually, respectively, which are statistically significant. The increase in daily electricity bill ($/day) is consistent with the daily electricity usage increase during the Winter and annually, as shown in Figure 35 and Table 40 for commercial TOU customers.

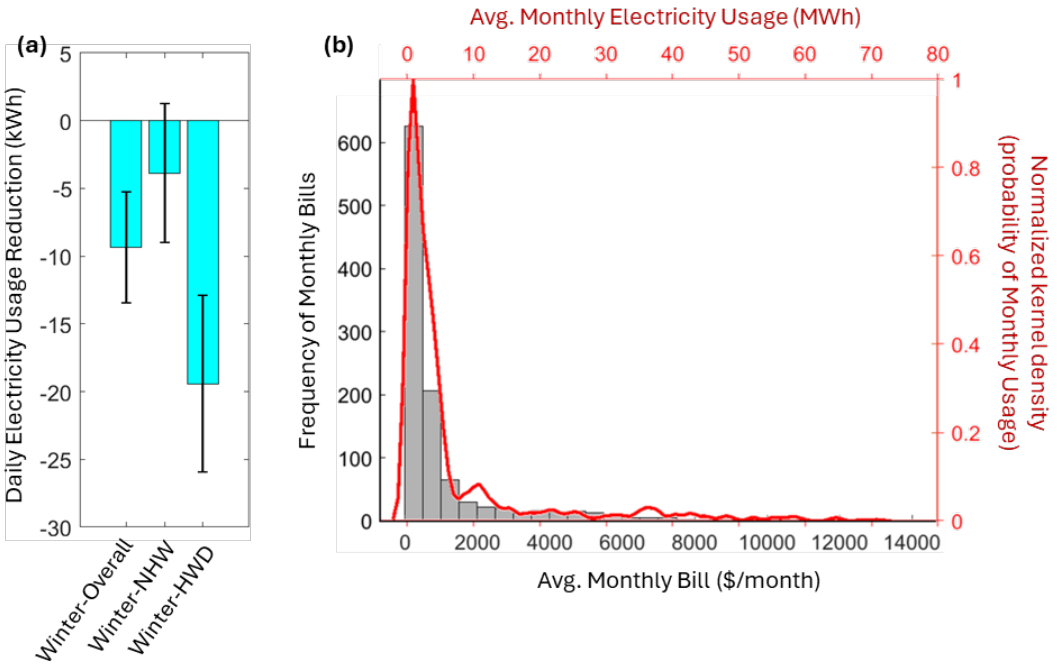
Table 40: Change in Daily Electricity Bill for Commercial TOU Participants

Parameters	Winter	Non-Winter	Annual Overall
Avg. Bill Savings ($/day)[a]	-12.3 ± 3.3	2.2 ± 2.2	-3.8 ± 2.6
Avg. Bill, Commercial TOU Participants, Pre-Pilot ($/day)	28.7	29	28.6
Relative Avg. Bill Savings (%)[a]	-42.8%	7.8%	-13.2%
Significance (p_Value≤0.05)	✓	X	✓

[a] Positive values represent 'Bill Savings' and Negative values represent 'Bill Increase.'

Interestingly, regardless that commercial customers demonstrated a significant increase in energy consumption during the non-Winter (Table 38), their average daily bill did not demonstrate statistically significant change as shown in Table 40.

Figure 35: (a) Average Reduction in Daily Electricity Usage (kWh) by Commercial TOU Participants, Where the Negative Reduction Represents an Increase in Usage. (b) Distribution of Average Monthly Electricity Bills ($/Month) and Average Monthly Electricity Usage (MWh) for Commercial TOU Customers



It should be noted that most commercial TOU participants in Phase 4 belong to the Small General business segment (32 customers), compared to 18 customers in the General segment, with no General rate class recruitment in Cohort 4 (Table 33). Figure 35b presents the distribution of average monthly electricity bills ($/month) and average monthly electricity usage (MWh) for commercial TOU customers used for the economic impact analysis. As illustrated in Figure 35b, the highest density of customers falls within the $600–$1,500 monthly bill range, which corresponds to the most frequent monthly electricity usage range of approximately 0.8–6 MWh. This distribution indicates that the economic impact results are primarily driven by the commercial TOU customers with small-to-medium electricity consumption, which is consistent with the predominance of Small General customers in the Phase 4 TOU sample.

5.2.2 Price Elasticity

Daily Price Elasticity reflects the change in overall daily electricity usage caused by changes in the average daily price ($) per kWh. It is expressed as the percent (%) change in the average electricity usage associated with a 1% increase in the daily average energy price. Inter-period Substitution Price elasticity reflects the participants' ability to substitute more expensive peak loads with less expensive off-peak loads and estimates changes in load shapes caused by a change in the peak-to-off-peak price ratio for all Winter days. It is expressed as the percent (%) change in the ratio of peak-to-off-peak average load associated with a 1% increase in the peak-to-off-peak price ratio.

The results demonstrated a Daily Price Elasticity of 0.13 (± 0.20) during Winter season and -0.21 (± 0.08) annual overall. The daily price elasticity during Winter season may imply that for 1% increase in the average daily price per kWh, the average daily electricity usage is increased by 0.13% during the Winter season; however, it is not statistically significant. In contrast, the annual daily price elasticity of -0.21 is statistically significant, suggesting that a 1% increase in the average daily price per kWh leads to an average reduction of approximately 0.21% in electricity usage over the year. Additionally, the inter-period substitution elasticity is estimated at -0.065 (± 0.02), which is statistically significant. It indicates that during Winter season a 1% increase peak-to-off-peak rate ratio results in 0.065% reduction in the peak-to-off-peak load ratio, reflecting load shifting from peak to off-peak periods.

6 Commercial CPP Tariff Impacts

This section presents and discusses the estimated load and economic impacts of the commercial CPP program. The goal of the commercial CPP pilot is to encourage customers to shift their electricity usage from peak events to off-peak periods when system utilization is lower. This is done by presenting customers with option to lower their energy bills if they participate in load shifting. The price differential is derived from system savings created in the near-term in the form of reduced fuel and purchased power costs, and over the longer-term in the form of avoided generation, transmission and distribution infrastructure costs.

This section presents and discusses the estimated load and economic impacts of the commercial CPP program, based on a Mixed-Effects modeling semi-DiD approach. The CPP Tariff impact analysis was conducted for CPP events called during Phase 4 from November 01, 2024, to March 31, 2025. Table 41 presents the CPP event dates along with the Starting and Ending times, average outdoor temperature, and the weekday status.

Table 41: List of CPP Events with Corresponding Starting/Ending Times, Average Outdoor Temperature, and Weekday Status

Event Number	Event Date	Event Start Time (Hour)	Event End Time (Hour)	Average Outdoor Temperature (°C)	Weekday Status
1	2024-12-04	17:00	21:00	-3.6	NHW[a]
2	2024-12-15	17:00	21:00	-2.5	Weekend
3	2024-12-20	7:00	11:00	-2.9	NHW
4	2024-12-22	17:00	21:00	-9.5	Weekend
5	2024-12-23	7:00	11:00	-9.0	NHW
6	2024-12-23	17:00	21:00	-9.0	NHW
7	2025-01-21	17:00	21:00	-9.1	NHW
8	2025-01-22	7:00	11:00	-13.1	NHW
9	2025-02-02	17:00	21:00	-9.9	Weekend
10	2025-02-05	17:00	21:00	-12.2	NHW
11	2025-02-06	7:00	11:00	-11.0	NHW
12	2025-03-04	7:00	11:00	-7.8	NHW
13	2025-03-10	7:00	11:00	-2.5	NHW
14	2025-03-11	7:00	11:00	-3.9	NHW

[a]NHW: Non-Holiday Weekdays

As shown in Table 41, three CPP events (Dec. 15, 2024, Dec. 22, 2024, and Feb. 02, 2025) took place during weekends. The morning and evening consecutive events occurred on December 23, 2024. The CPP events include seven morning and seven evening events, where the coldest (-13.1 °C) event day took place on January 22, 2025.

Commercial CPP customer participation for Phase 4 is currently at 28 participants. Contrary to commercial TOU, most of the enrolment for commercial CPP occurred in Cohort 4. A summary of Commercial CPP sample size used in the analysis is summarized in Table 42.

Table 42: Summary of Commercial CPP Sample Size[11]

Parameter	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Sample Size	4	1	3	20	28
Rate Class					
Small General	2	0	1	8	11
General	2	1	2	12	17
Region					
HRM	2	0	3	16	21
Rest of Nova Scotia	2	1	0	4	7

6.1 Load Impacts

This section presents and discusses the electrical load impact from the commercial CPP pilot.

6.1.1 Change in Load during Peak Events

Table 43 summarizes the results of the analysis for morning and evening CPP events for all cohorts of commercial CPP participants in Phase 4, where the average load reduction values are presented along with their MoE at 90% confidence level. The commercial CPP participants demonstrated significant average load reductions during morning and evening CPP events with a relative load reduction of 10.4% overall for all events.

Table 43: Change in Load during CPP Events for Commercial CPP Participants

Parameters	Morning Events	Evening Events	All Events
Avg. Load Reduction (kW)[a]	7.9 ± 2.9	5.1 ± 2.7	6.3 ± 2.3
Avg. Load – Commercial CPP Participants, Pre-Pilot (kW)	69.5	64.7	65.7
Relative Avg. Load Reduction (%)[a]	11.4%	7.9%	9.6%
Significance (p_Value≤0.05)	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

Figure 36 illustrates the daily load profile for commercial CPP participants during pilot period on CPP days compared to reference days with morning events only, evening events only, and double events, as well as for all event days. The CPP participants exhibit load shift during morning events (Figure 36a, c) and evening events (Figure 36b, c), compared to reference days. In overall, the CPP participants demonstrated load reduction during CPP events, indicating shifting their load compared to their load during reference days (Figure 36d).

[11] Participation in this table differs from the participation summary found in Table 5 as some participants are removed due to not meeting AMI data criteria necessary for the regression analysis. Refer to the seasonal load ratio analysis in equation (13) and cleaning steps in Table 69.

Figure 36: Load Shapes for Commercial CPP Participants on Event Days (a) with Morning Only Events, (b) with Evening Only Events, (c) with Both Morning and Evening Events, and (d) for All Event Days

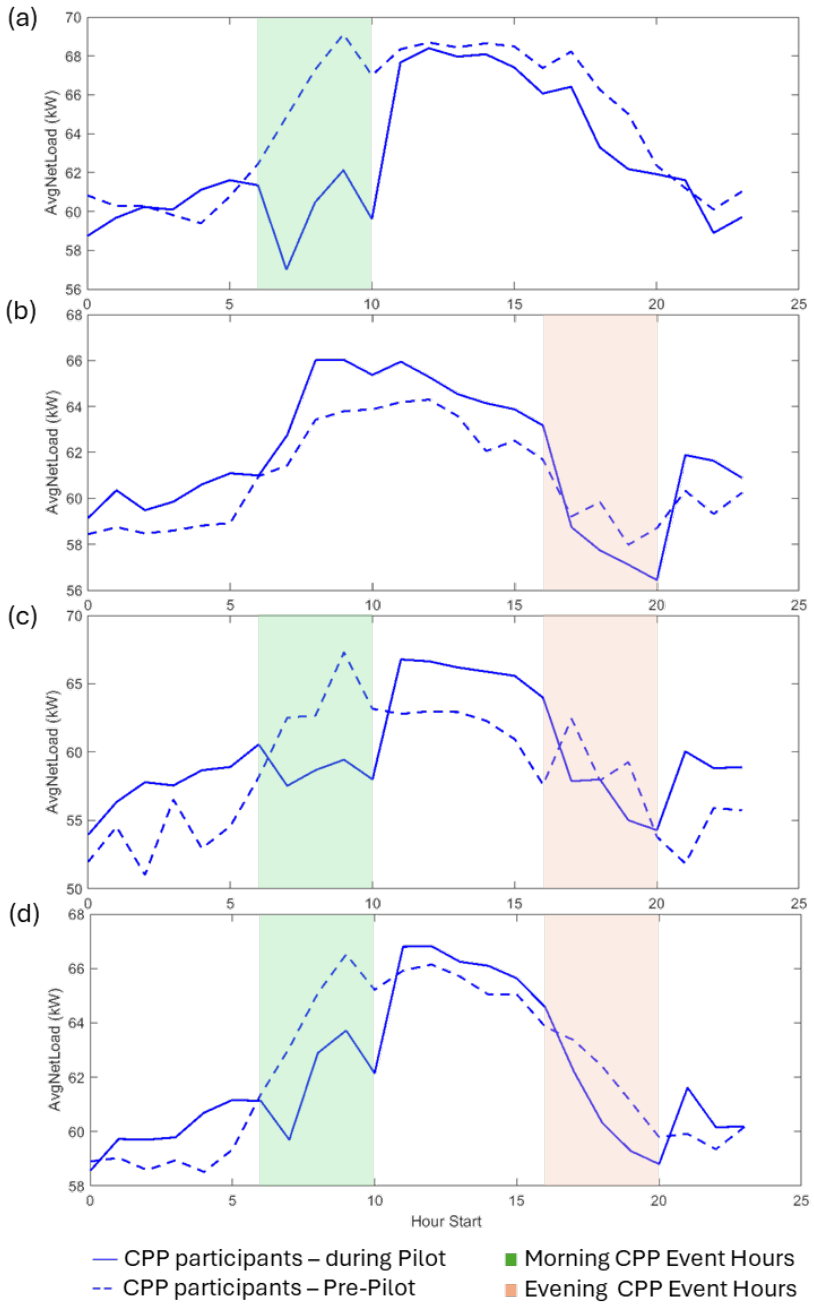
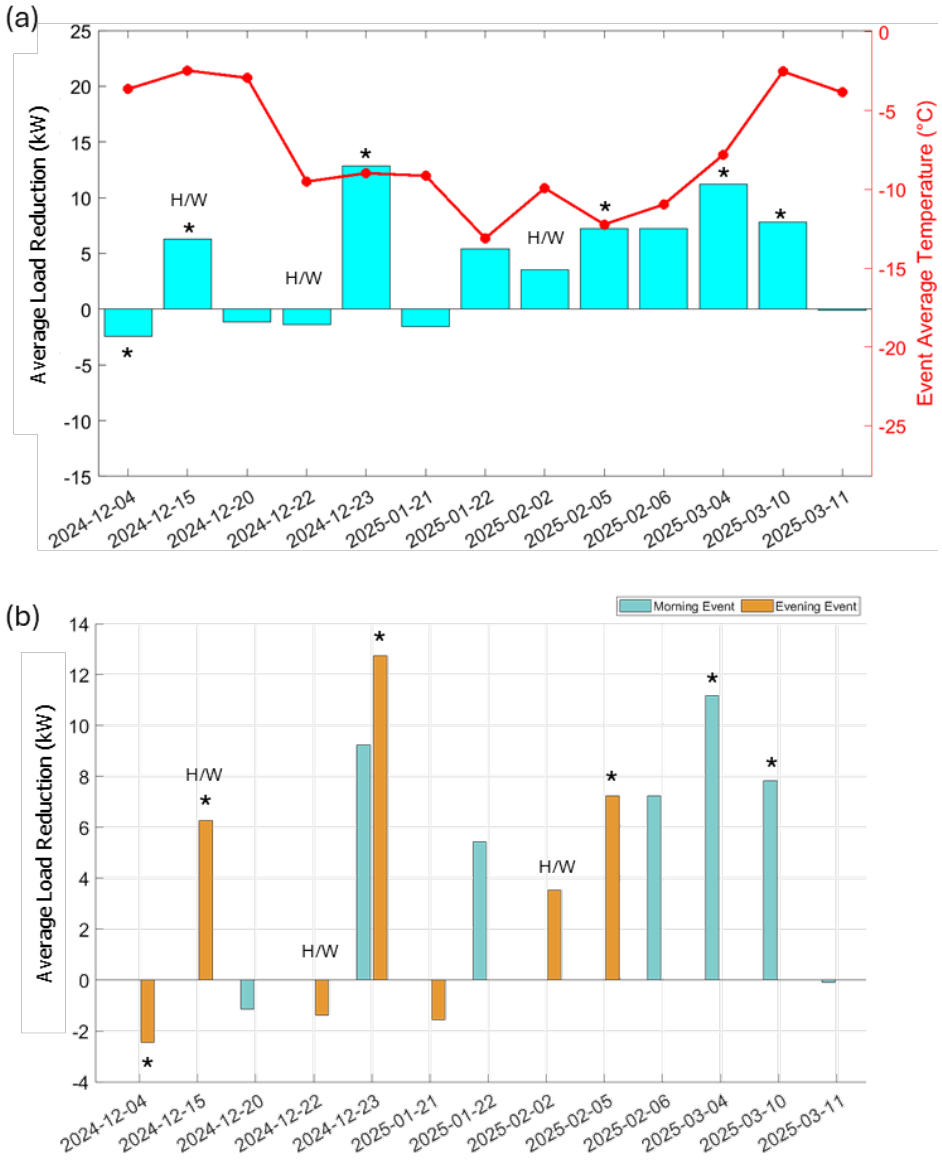


Figure 37a presents the average load reduction (kW) per CPP event date for all Phase 4 cohorts, along the corresponding event-average outdoor temperature (°C). Overall, commercial CPP participants exhibit load reductions on most event days, with a statistically significant average load reduction of 6.3 kW across all events. However, statistically significant load reductions can be observed on December 15, 2024; December 23, 2024; February 5, 2025; March 4, 2025; and March 10, 2025

(Figure 37a). Although most CPP events occurred on weekdays, three events took place on weekends. Among these, a statistically significant average load reduction of approximately 6 kW is observed on December 15, 2024 (Figure 37a).

Figure 37: (a) Average Load Reduction (kW) per CPP Event Along with Average Event Temperature (°C), and (b) Average Load Reduction per CPP Event Date by Morning, Evening, or Morning and Evening CPP Event.



* Statistically Significant (p_Value≤0.05, H/W: Holiday/Weekend)

Across all statistically significant event dates, average load reductions range from 6.3 kW to 12.9 kW, occurring on December 15, 2024, and December 23, 2024, respectively (Figure 37a). Notably, the lowest temperature at which a statistically significant load reduction is observed is −12.2 °C on February 5, 2025, corresponding to an average load reduction of 7.2 kW (Figure 37a).

Figure 37b further disaggregates results of the average load reduction by morning and/or evening events per CPP event date. Notably, commercial CPP participants exhibited an average load increase for three evening events, although the load increase (approximately 2.8 kW) was statistically significant only during the evening event on December 4, 2024. The CPP participants also showed average load increases of 1.1 kW and 0.09 kW for two morning events on December 20, 2024 and March 11, 2025, respectively, but they were not statistically significant.

There was only one instance of two consecutive CPP events in the same day, which occurred when events 5 and 6 took place on December 23, 2024. The second of these consecutive events led to the highest load reduction among CPP customers in Phase 4. This suggests that being preceded by another CPP event did not negatively affect the performance of this event. However, because Phase 4 includes only a single occurrence of consecutive events, the available data is insufficient to draw broader conclusions about the overall impact of consecutive CPP events.

Notably, performing this analysis on individual hours for each event in a similar manner to the residential rate class would further reduce the power of the regression and ultimately create statistically insignificant results.

Change in Load during Peak Events by Region

Table 44 presents the average load reduction (kW) by region (Halifax area versus the rest of Nova Scotia) for commercial CPP participants during morning, evening, and all CPP events. Commercial CPP participants located in the Halifax area exhibit statistically significant load reductions during both morning and evening events, with an average load reduction of 8.6 kW for all events, corresponding to a 10.7% relative reduction in load. In contrast, commercial CPP participants in the rest of Nova Scotia exhibit an average load increase of 0.7 kW across all events, which is not statistically significant.

Table 44: Change in Load during CPP Events by Region for Commercial CPP Participants

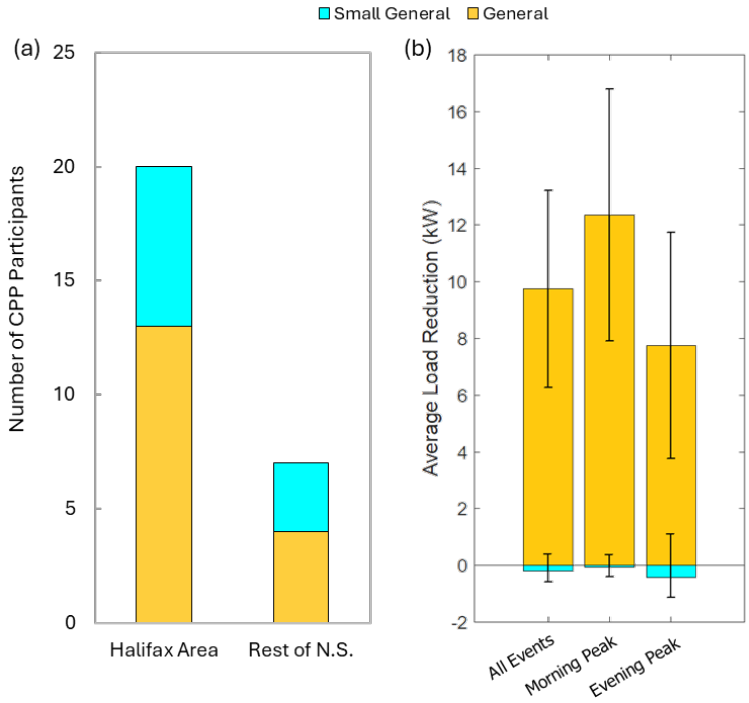
Parameters	Halifax Area			Rest of Nova Scotia		
	Morning Events	Evening Events	All Events	Morning Events	Evening Events	All Events
Avg. Load Reduction (kW)[a]	10.6 ± 3.8	7.0 ± 3.4	8.6 ± 3.0	-0.1 ± 0.6	-1.0 ± 1.0	-0.7 ± 0.7
Avg. Load – Commercial CPP Participants, Pre-Pilot (kW)	84.4	75.9	80	19.7	16.4	18.3
Relative Avg. Load Reduction (%)[a]	12.6%	9.2%	10.7%	-0.3%	-6.0%	-3.7%
Significance (p_Value≤0.05)	✓	✓	✓	X	X	X

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase'.

The observed differences in average load reductions between the Halifax area and the rest of Nova Scotia may be partially explained by differences in the composition and sample size of business types across regions. Figure 38a illustrates the distribution of General and Small General commercial CPP participants in the Halifax area compared to the rest of Nova Scotia. As shown, the sample size of commercial CPP participants in the rest of Nova Scotia is substantially smaller than that within the Halifax area. Specifically, the Halifax area includes 13 General commercial CPP participants, compared to only 4 General commercial CPP participants in the rest of Nova Scotia.

Given that General commercial CPP participants exhibit significantly larger average load reductions across all CPP events, compared to the statistically insignificant load reductions among Small General participants (Figure 38b), the higher number of General commercial CPP participants in the Halifax area likely contributes to the greater load reductions by the commercial CPP customers in that region, as presented in Table 44.

Figure 38: (a) Distribution of Number of General and Small General Commercial CPP Participants in Halifax Area and the Rest of Nova Scotia, and (b) the Average Load Reduction (kW) for General and Small General Business Types



6.1.2 Snapback Effect

The snapback effect refers to commercial CPP customers that use more electricity than the baseline during the hours immediately following CPP event hours, compared to the pre-pilot period. This effect was evaluated based on the same Mixed Effect approach that was applied to the load reduction calculation, but specifically for the four hours following the CPP event. As summarized in Table 45, CPP commercial participants exhibit statistically insignificant morning and evening snapback effect with an insignificant overall snapback of 0.5 kW load increase. However, the CPP participants exhibited a significant snapback of 6.9 kW of load increase during the event days with both morning and evening CPP events.

Table 45: Snapback Effect for Commercial CPP Participants

Parameters	Avg. Load Reduction [a] (kW)	Significance (p_Value≤0.05)
Morning Snapback	0.6 ± 0.9	X
Evening Snapback	-0.1 ± 1.3	X
Morning & Evening Snapback [b]	-6.9 ± 3.4	✓
Overall Snapback	-0.5 ± 1.1	X

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

[b] Applies to the event day(s) with both morning and evening CPP peak hours.

6.1.3 Change in Load during Highest ANL Hours

Figure 39 depicts the distribution of Top 20, 50 and 88 highest ANL hours for commercial CPP participants during weekdays and weekends as well as across CPP events. As seen in Figure 39a–c, the majority of the highest ANL hours occurred on weekdays. Specifically, 55%, 36% and 27% of the top 20, 50, and 88 ANL hours, respectively, take place during peak periods. In addition, approximately 40%, 28% and 21% of all CPP events, which coincided with the highest top 20, 50 and 88 ANL hours, respectively, occurred during weekdays, while only 15%, 8% and 6% of CPP events, which coincide with top 20, 50 and 88 ANL hours, took place on Weekends.

Figure 39: Distribution of Top 20, Top 50 and Top 88 ANL Hours by Day Type (Weekday / Weekend) and Commercial CPP Events

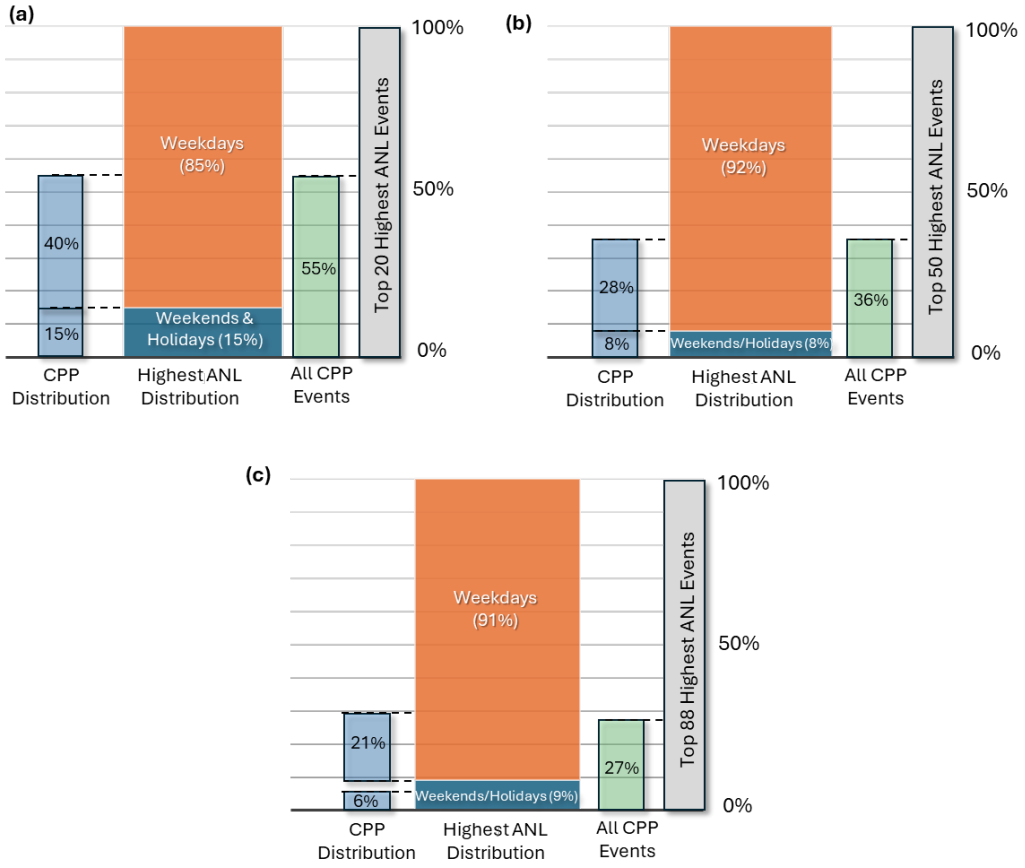


Table 46 summarizes the estimated changes in load for commercial CPP participants during the highest ANL hours overall, as well as during ANL hours that coincide with CPP peak periods. Results indicate that participants achieved statistically significant load reductions during the top 20, 50, and 88 highest ANL hours. Focusing specifically on ANL hours that coincide with CPP peak periods, the CPP participants exhibit slightly higher average load reductions during the top 20, 50 and 88 ANL hours compared to the corresponding highest ANL hours overall.

Table 46: Change in Load (kW) during Highest Winter ANL Hours for Commercial CPP Participants

Parameters	Highest ANL Hours			ANL Hours Coincide CPP Events		
	Top 20	Top 50	Top 88	Top 20	Top 50	Top 88
Avg. Load Reduction (kW)[a]	6.8 ± 3.3	6.6 ± 2.8	5.0 ± 2.1	7.4 ± 3.4	8.2 ± 3.1	7.4 ± 2.6
Avg. Load Participants, Pre-Pilot (kW)	64.4	61.4	61.6	64.1	61.3	61.2
Relative Avg. Load Reduction (%)[a]	10.6%	10.7%	8.1%	11.6%	13.3%	12.0%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase'.

6.1.4 Change in Usage

Changes in electricity usage were estimated by applying the same Mixed-Effect modeling approach that was used for estimating hourly load impact, where the change in daily usage levels was evaluated through two analyses. For the first analysis, the daily usage reduction was evaluated during event days, when at least one CPP event occurred, compared to reference days. For the second analysis, the daily electricity usage levels were evaluated for Winter and non-Winter days during the treatment period compared to the pre-pilot period.

The first analysis revealed that for all event days combined, commercial CPP participants reduced their daily electricity usage by an average of 65 kWh/day (±1.3 kWh/day) compared to reference days, which is statistically significant. The results from the second analysis are summarized in Table 47, which presents the estimated changes in daily electricity usage (kWh/day) for commercial CPP participants. As shown in Table 47, when disaggregated by day type, the CPP participants exhibit statistically significant daily usage reduction of approximately 54 kWh/day during Winter, 51 kWh/day during non-holiday weekdays in Winter, and 62 kWh/day during holiday/weekends in Winter. In contrast, the participants experienced a significant daily usage increase of 21 kWh/day during non-Winter season.

Table 47: Change in Daily Electricity Usage (kWh/day) for Commercial CPP Participants

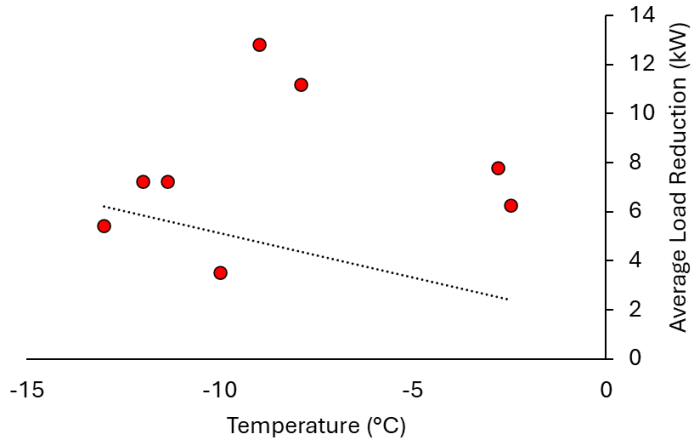
Parameters	Winter Overall	Winter – Non-Holiday Weekdays	Winter – Holiday Weekends	Non-Winter	Annual Average
Avg. Usage Reduction (kWh/day)[a]	54.0 ± 10.9	51.2 ± 11.6	62.3 ± 16.6	-21.4 ± 3.7	-12.2 ± 6.7
Avg. Usage – Commercial CPP Participants, Pre-Pilot (kWh/day)	1627	1646	1595	141	720
Relative Usage Reduction (%)[a]	3.4%	3.1%	3.9%	-15.2%	-1.7%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓

[a] Positive values represent 'Usage Reduction' and Negative values represent 'Usage Increase.'

6.1.5 Effect of Weather (Temperature) on Load Reduction

The DiD analysis reveals that the average load reduction is increased by 0.06 kW (± 0.35 kW) per 1 °C decrease in outdoor temperature, which is not statistically significant. It implies that commercial CPP customers exhibit statistically insignificant changes in their load reduction when the weather becomes colder, although the correlation between average load reduction (kW) and average outdoor temperature during CPP event days shows an upward trend with respect to colder temperature (Figure 40).

Figure 40: The Correlation of Load Reduction by Commercial CPP Participants with Outdoor Temperature



6.1.6 Effect of Consecutive CPP Events on Load Reduction

During Phase 4, like Phase 3, there was only one instance of two consecutive CPP events, which occurred when events 5 and 6 took place on December 23, 2024. The second of these consecutive events (evening event 6) led to a higher load reduction, which is statistically significant, compared to

its preceding event (morning event 5). This suggests that being preceded by another CPP event did not negatively affect the load reduction by CPP residential customers during this event. However, because Phase 4 includes only a single occurrence of consecutive events, the available data is insufficient to draw broader conclusions the overall impact of consecutive CPP events. The individual event load impacts are displayed in Figure 37.

6.2 Economic Impacts

This section presents and discusses the impact of commercial CPP tariffs on the electricity bill as well as price elasticity.

6.2.1 Change in Electricity Bills

The bill impact analysis for the commercial CPP uses the same method that was used for estimating the commercial CPP load impact analysis. In the bill impact analysis, applicable tariffs were applied in accordance with the customer type and pilot period, as summarized in Table 48. Note details on these tariffs are included in Attachment I: Riders and Tariff Structure.

Table 48: Tariffs Used for Analyzing Commercial CPP Impact on Electricity Bill

Customer Type	Period	Applicable Tariff
Treatment – General	Pre-Pilot	General Tariff – Rate Code 11
Treatment – General	Pilot	General CPP Tariff – Rate Code 73
Treatment – Small General	Pre-Pilot	Small General Tariff – Rate Code 10
Treatment – Small General	Pilot	Small General CPP Tariff – Rate Code 72

Table 49 presents the estimated average daily bill savings for all cohorts of commercial CPP participants over the Winter season in Phase 4. The commercial CPP customers experienced an average Bill Saving of $12 per day, corresponding to 5.8% saving relative to their daily electricity bill in pre-pilot period, which is statistically significant.

Table 49: Change in Daily Electricity Bill for Commercial CPP Participants

Parameters	Winter	Non-Winter	Annual Average
Avg. Bill Savings ($/day)[a]	11.7 ± 10.1	-1.5 ± 1.9	10.3 ± 7.0
Avg. Bill, Commercial CPP Participants, Pre-Pilot ($/day)	203	20	149
Relative Avg. Bill Savings (%)[a]	5.8%	7.7%	6.9%
Significance (p_Value≤0.05)	✓	X	✓
[a] Positive values represent 'Bill Savings' and Negative values represent 'Bill Increase.'			

Interestingly, regardless that commercial customers demonstrated a significant increase in energy consumption during the non-Winter (Table 47), their average daily bill did not demonstrate statistically significant change as shown in Table 49. This is attributable to the decrease in CPP volumetric energy cost negating the increase in energy consumption during the non-Winter period. Furthermore, commercial CPP participants managed to reduce their annual electricity bill while increasing their overall energy consumption.

6.2.2 Price Elasticity

NS Power evaluated price elasticity to measure commercial CPP participants' responsivity to electricity prices during Phase 4 of the pilot. Specifically, NS Power evaluated Daily Price Elasticity during Winter season and annual overall, as well as the Inter-period Substitution Price Elasticity during Winter season.

Daily Price Elasticity reflects the change in overall daily electricity usage caused by changes in the average daily price ($) per kWh. It is expressed as the percent (%) change in the average electricity usage associated with a 1% increase in the daily average energy price. Inter-period Substitution Price elasticity reflects the participants' ability to substitute more expensive peak loads with less expensive off-peak loads and estimates changes in load shapes caused by a change in the peak-to-off-peak price ratio for all Winter days. It is expressed as the percent (%) change in the ratio of peak-to-off-peak average load associated with a 1% increase in the peak-to-off-peak price ratio.

The analysis reveals Daily Price Elasticity of -0.38 (± 0.07) during Winter season and -0.48 (± 0.08) annual overall. It indicates that for 1% increase in the average daily price per kWh, the average daily electricity usage decreases by 0.38% during Winter and 0.48% over the year, which are statistically significant. Furthermore, the inter-period substitution elasticity is estimated at -0.14 (± 0.15), indicating that a 1% increase in the ratio of peak-to-off-peak rates can potentially lead to a decrease of 0.14% in the peak-to-off-peak load ratio by the commercial CPP customers, which is not statistically significant.

7 MURB TOU Tariff Impacts

As this Phase represents the first year of the MURB TOU pilot program, participation was limited to 10 enrolled MURBs, with the pilot period beginning on November 1, 2024. The goal of the MURB TOU pilot is to inform if removing the demand charge for select customer segments on the General Rate will enable additional load shifting potential compared to the commercial TOU pilot. This section presents and discusses the estimated impacts of the commercial TOU pilot with respect to load and economics.

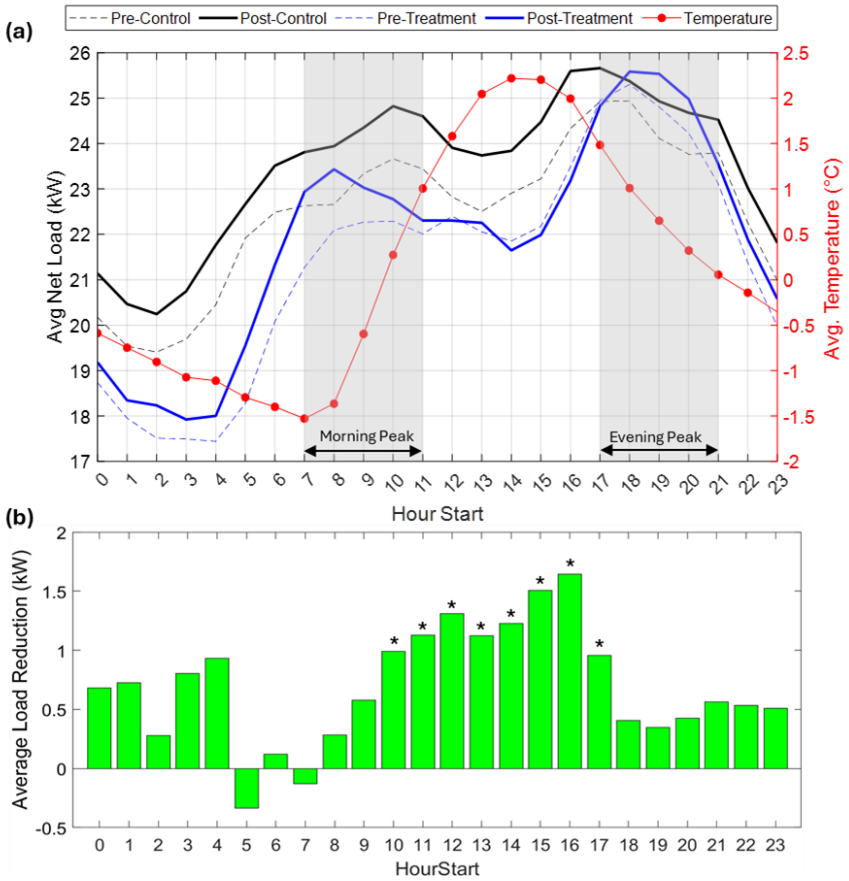
7.1 Load Impacts

This section presents and discusses the electrical load impact from the commercial MURB TOU pilot.

7.1.1 Change in Load during Peak Periods

Figure 41a illustrates the load profiles for MURB TOU participants and the control group during the pre-pilot and pilot periods with the corresponding variation in outdoor temperature. Although MURB TOU participants demonstrate reduction in load most hours except at 5 AM and 7 AM (Figure 41b), the load reduction is statistically significant from 10–11AM during morning peak period and during mid-peak hours between 11 AM – 5 PM and the first hour of the evening peak period from 5 – 6 PM (Figure 41b).

Figure 41: (a) The Hourly-Averaged Load Shapes during Winter for MURB TOU including Pre-Treatment, Post-Treatment, Pre-Control and Post-Control Groups along with the Variation of Average Outdoor Temperature during Pilot Period, and (b) the Hourly Average Load Reduction (kW)



*Represents statistically significant load reduction.

As presented in Table 50, on average, the DiD analysis reveals that MURB TOU participants exhibit a statistically significant overall load reduction of 1.9% in electrical load. Notably, average relative load reductions of 1.8% and 2.1% during the morning peak (7 – 11 AM and evening peak (5 – 9 PM) were observed respectively. Overall, during morning and evening peak periods the average reduction of approximately 480 W in load during morning and evening peak periods, which is statistically significant. Interestingly, higher relative load reductions of 5.5% and 2.2% were observed during mid-peak (11 AM – 5 PM) and off-peak hours (9 PM – 7 AM), respectively. Table 50 summarizes the results of the DiD analysis for the morning, evening, and the overall load impact. Estimated impacts are presented alongside MoE at the 90% confidence level.

Table 50: Change in Load during MURB TOU Morning and Evening Peak Hours, Mid-Peak and Overnight Peak hours, and Overall during Morning and Evening Peaks in Winter

Parameters	Morning Peak	Mid-Peak Period[b]	Evening Peak	Overnight Period[c]	Overall On-Peak
Avg. Load Reduction (kW)[a]	0.44 ± 0.49	1.34 ± 0.40	0.54 ± 0.49	0.48 ± 0.31	0.48 ± 0.35
Avg. Load – MURB TOU Participants, Pre-Pilot (kW)	24.2	24.4	25.1	22.0	24.7
Relative Avg. Load Reduction (%)[a]	1.8%	5.5%	2.1%	2.2%	1.9%
Significance (p_Value≤0.05)	X	✓	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

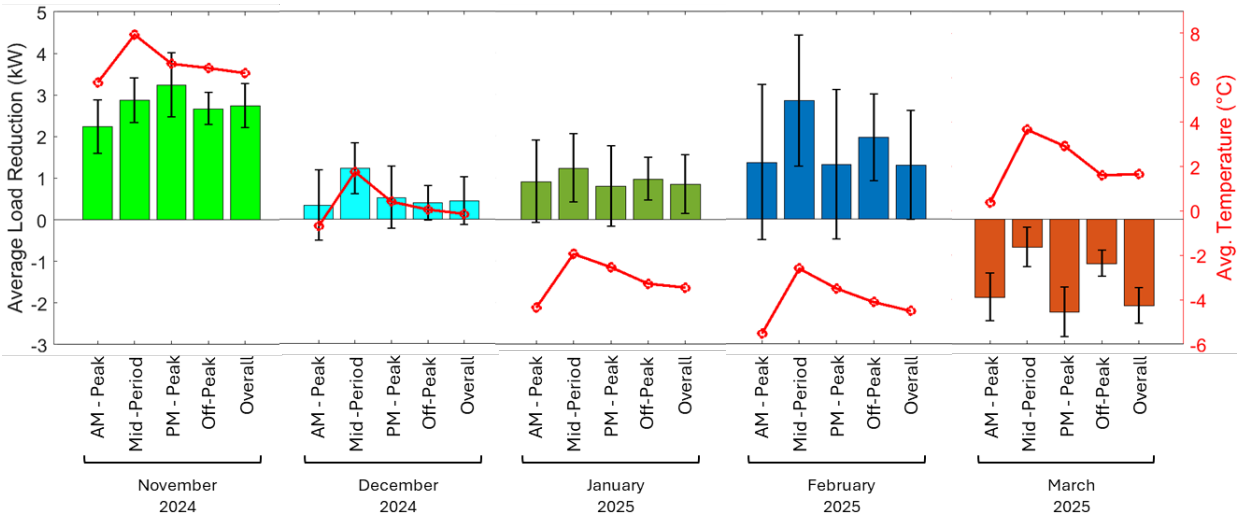
[b] Mid-peak hours are between 11 AM – 5 PM. Note: Mid-peak hours are not considered as a TOU-Peak period.

[c] Overnight period is between 9 PM – 7 AM.

Change in Load by Month during Peak Periods

Figure 42 illustrates the impact of MURB TOU on average load reduction (kW), along with corresponding average outdoor temperature (°C) during peak periods as well as mid-peak and off-peak hours by month over the Winter season (November 2024–March 2025). Overall, MURB TOU participants exhibit overall load reductions in Winter season except for March. However, the load reductions were statistically significant only in November and January. In contrast, during March, the MURB TOU customers experienced overall load increase of 9.5% during morning and evening peak hours (Figure 42). The largest load reduction of 14.5% occurred during the evening peak in November when outdoor temperatures were above 7 °C. In contrast, the MURB TOU participants experienced the highest load increase of 9.8% during the evening peak in March 2025 when average temperatures were 3 °C. Notably, during the coldest months, when average temperatures were below zero in January and February 2025, MURB TOU participants demonstrated statistically significant load reductions during mid-peak period and evening peak hours. Overall, as indicated in Table 50, MURB TOU participants showed an average load reduction of 0.48 kW during morning and evening peak hours in Winter season, which is statistically significant.

Figure 42: Average Net Load Reduction (kW) and Temperature Variation during MURB TOU Peak Period in Winter for the Months of January, February, March, November and December



7.1.2 Snapback Effect

The snapback effect refers to premises that use more electricity than the baseline during the hours immediately following peak periods, compared to the pre-pilot period. This effect is evaluated based on the same DiD approach that was applied to the load reduction calculation, but specifically for the four hours following the morning and evening peak hours. As summarized in Table 51, MURB TOU participants exhibit average load reductions of 1.2 kW and 0.53 kW during the morning and evening snapback periods, respectively, although only the load reduction during morning snapback period was statistically significant.

Table 51: Snapback Effect for MURB TOU Participants in Winter

Parameters	Avg. Load Reduction (kW)[a]	Relative Avg. Load Reduction (%)[a]	Significance (p_Value≤0.05)
Morning Snapback[b]	1.20 ± 0.48	5.0%	✓
Evening Snapback[c]	0.53 ± 0.54	2.3%	X
Overall Snapback	0.92 ± 0.36	3.9%	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

[b] From 11 AM – 2 PM; [c] From 9 PM – 1 AM.

7.1.3 Change in Load during Highest ANL Hours

Figure 43 depicts the distribution of Top 20, 50 and 88 highest ANL hours for MURB TOU participants during morning peak, evening peak, mid-peak, and off-peak hours. As seen in Figure 43a-c, the majority of the highest ANL hours occurred on morning and evening peak hours.

Figure 43: Distribution of Top 20, Top 50 and Top 88 ANL Hours by Day Type (Weekday / Weekend) and MURB TOU Period

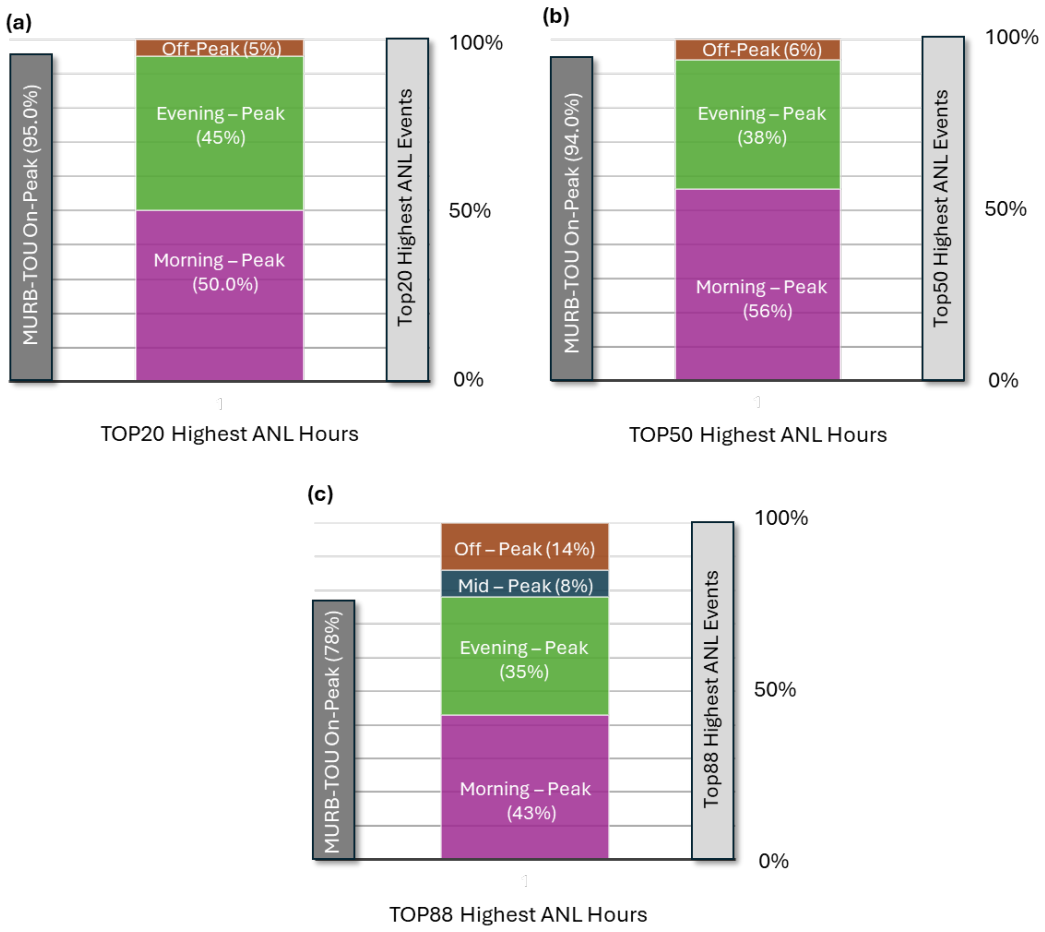


Table 52 summarizes the estimated changes in load during the highest ANL hours overall, as well as during ANL hours that coincide with TOU peak periods. Results indicate that MURB TOU participants exhibit load reduction during the top 20, 50, and 88 highest ANL hours, although only reductions during the top 50 and 88 highest ANL hours are statistically significant. When focusing specifically on ANL hours that coincide with TOU peak periods, participants exhibit load reductions of 9.6%, 12.2% and 9.1% during top 20, 50, and 88 hours, although only load reductions during top 50 and 88 are statistically significant.

Table 52: Change in Load (kW) during Highest Winter ANL Hours for MURB TOU Participants

Parameters	Highest ANL Hours			ANL Hours Coincide TOU Peak Periods		
	Top 20	Top 50	Top 88	Top 20	Top 50	Top 88
Avg. Load Reduction (kW)[a]	3.3 ± 4.0	4.2 ± 2.9	3.2 ± 2.1	2.9 ± 4.2	3.7 ± 3.0	2.8 ± 2.5
Avg. Load – MURB TOU Participants, Pre-Pilot (kW)	31.3	30.6	30.2	30.6	30.1	30.2
Relative Avg. Load Reduction (%)[a]	10.4%	13.9%	10.6%	9.6%	12.2%	9.1%
Significance (p_Value≤0.05)	X	✓	✓	X	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

7.1.4 Change in Usage

Changes in daily electricity usage were estimated by applying the same DiD approach that was used for estimating hourly load impact. Table 53 presents the estimated changes in daily electricity usage (kWh/day) for MURB TOU participants.

Table 53: Change in Daily Electricity Usage (kWh/day) for MURB TOU Participants

Parameters	Winter Overall	Winter Months				
		January	February	March	November	December
Avg. Usage Reduction (kWh/day)[a]	16.5 ± 30	22 ± 45	33 ± 97	-34 ± 35	66 ± 68	11 ± 34
Avg. Usage – MURB TOU Participants, Pre-Pilot (kWh/day)	563	612	639	513	488	569
Relative Usage Reduction (%)[a]	2.9%	3.6%	5.1%	-6.6%	13%	1.9%
Significance (p_Value≤0.05)	X	X	X	X	X	X

[a] Positive and negative values represent 'Usage Reduction' and 'Usage Increase.'

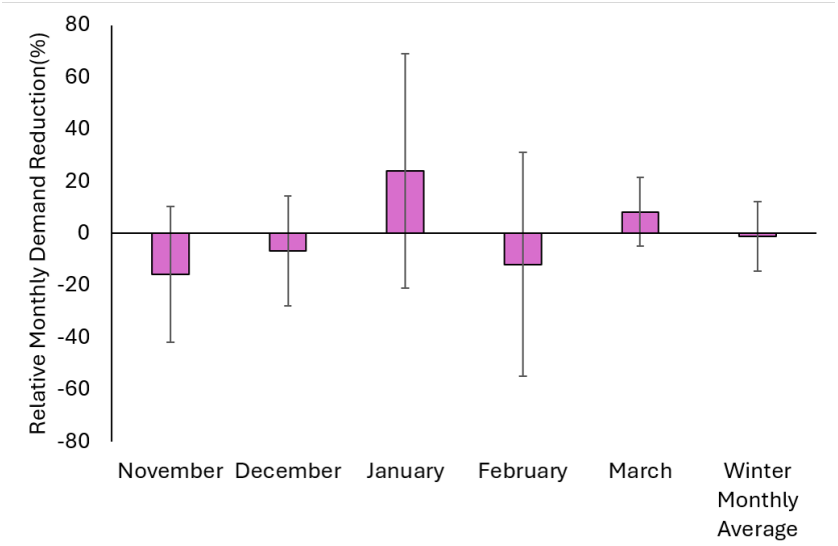
As shown in Table 53, although MURB TOU participants exhibit reductions in daily electricity usage during Winter season, the daily electricity usage reduction is not statistically significant.

7.1.5 Change in Demand

Demand for this evaluation is defined as the maximum 15-minute electricity consumption in terms of power (kW) calculated at AMI interval data frequency (i.e. every 15 minutes). Figure 44 illustrates a comparison of relative changes in monthly demand during Winter months and on average across the Winter for MURB TOU participants. Although MURB TOU participants exhibited potential indications of relative monthly demand reductions in January and March, and increases in November, December, and February, these changes were not statistically significant. Overall,

participants demonstrated statistically insignificant average changes in monthly demand during the Winter period (Figure 44).

Figure 44: Comparison of Relative Change in Monthly Demand (%) during Winter overall and among Winter Months (Jan, Feb, Mar, Nov, Dec).



Note: 'Positive' and 'Negative' relative demand reduction (%) represent 'Reduction' and 'Increase,' respectively.

Table 54 summarizes changes in monthly maximum demand among MURB TOU participants during the Winter months and for Winter 2024/25 overall. Results indicate that participants exhibited no statistically significant changes in monthly maximum demand during individual Winter months or across the Winter period.

Table 54: Change in Monthly Demand by MURB TOU Participants during Winter Months and Winter Overall

Parameters	Winter Overall	Winter Months				
		January	February	March	November	December
Avg. Monthly Demand Reduction (kW)[a]	-0.12 ± 1.62	3.28 ± 6.13	-1.66 ± 6.01	0.87 ± 1.38	-1.65 ± 2.76	-0.84 ± 2.64
Avg. Monthly Demand – MURB TOU Participants, Pre-Pilot (kW)	12.2	13.6	13.9	10.4	10.5	12.5
Relative Avg. Monthly Demand Change (%)[a]	-1.0%	24.0%	-11.9%	8.3%	-15.7%	-6.7%
Significance (p_Value≤0.05)	X	X	X	X	X	X

[a] Positive values represent 'Demand Reduction' and Negative values represent 'Demand Increase.'

Figure 45 illustrates the estimated relative demand reduction (%) overall and across specific TOU periods, including pre-morning peak, morning peak, morning snapback, pre-evening peak, evening peak, and evening snapback. During the Winter 2024/25 evaluation period, 5% during morning snapback hours between 11:00 AM and 3:00 PM and pre-evening peak hours between 3:00 PM – 5:00 PM. Although MURB TOU customers demonstrate increase in demand during pre-morning peak and reductions in demand during morning peak, evening peak and evening snapback hours, these changes in demand are not statistically significant (Figure 45). Notably, the effect on demand per period as visualized in Figure 45 is not a determinant for billing and should be interpreted with caution when comparing to Figure 44 which visualizes monthly demand.

Figure 45: Relative Demand Reduction (%) by MURB TOU Participants during Pre-Morning Peak (5–7 AM), Morning Peak (7–11 AM), Morning Snapback (11AM–3PM), Pre-Evening Peak (3–5 PM), Evening Peak (5–9 PM), and Evening Snapback (9PM – 1AM) during Winter

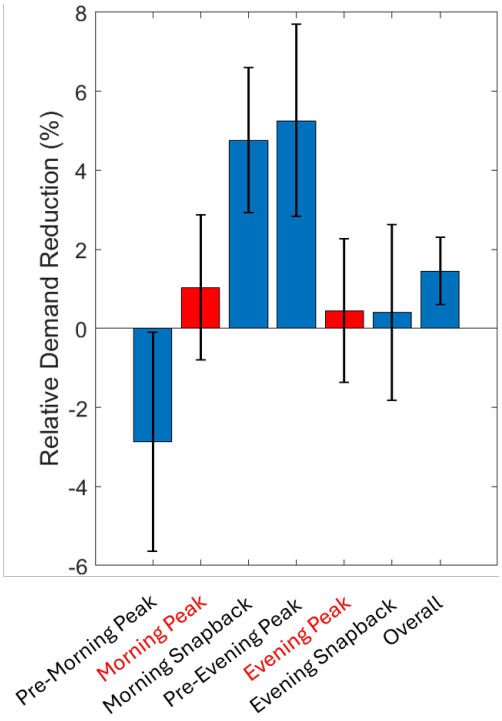


Table 55 summarizes changes in demand by MURB TOU participants during Pre-Morning Peak, Morning Peak, Morning Snapback Period, Pre-Evening Peak, Evening Peak and Evening as well as the overall and Snapback periods during Winter 2024/25. Notably, the estimated overall demand reduction of 1.4% is statistically significant, where MURB TOU participants demonstrate statistically significant demand reductions of 4.7% and 5.2% during morning snapback and pre-evening peak periods, respectively.

Table 55: Changes in Demand by MURB TOU Participants during Winter

Parameters	Pre-Morning Peak[b]	Morning Peak[c]	Morning Snapback[d]	Pre-Evening Peak[e]	Evening Peak[f]	Evening Snapback[g]	Overall Daily
Avg. Demand Reduction (kW)[a]	-0.2 ± 0.2	0.1 ± 0.1	0.3 ± 0.1	0.4 ± 0.2	0.03 ± 0.1	0.03 ± 0.14	0.1 ± 0.06
Avg. Demand – MURB TOU Participants, Pre-Pilot (kW)	6.6	7.0	6.8	7.2	7.2	6.6	6.7
Relative Avg. Demand Change (%)[a]	-2.9%	1.0%	4.7%	5.2%	0.4%	0.4%	1.4%
Significance (p_Value≤0.05)	X	X	✓	✓	X	X	✓

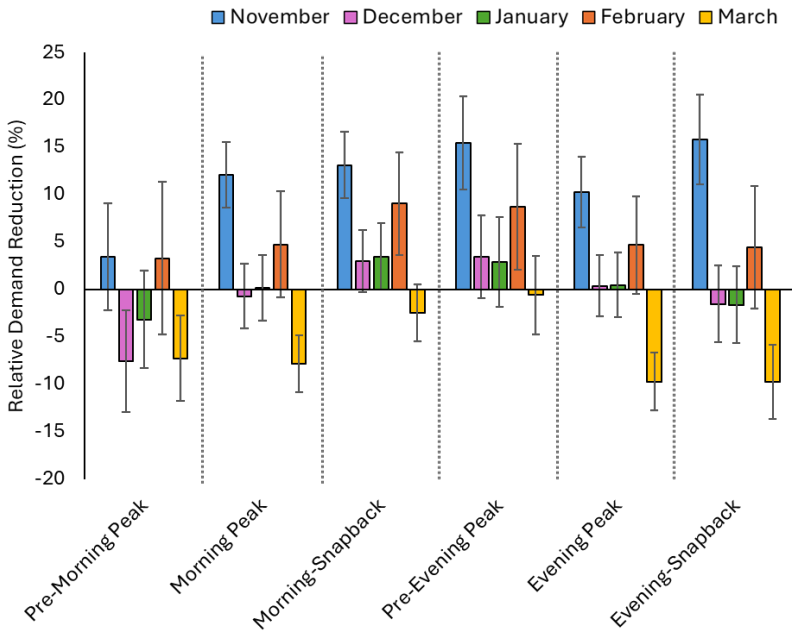
[a] Positive values represent 'Demand Reduction' and Negative values represent 'Demand Increase'.

[b] between 5 AM and 7 AM; [c] between 7 AM and 11 AM; [d] between 11 AM and 3 PM; [e] between 3 PM and 5 PM;

[f] between 5 PM and 9 PM; [g] between 9 PM and 1 AM.

Figure 46 compares the relative demand reduction (%) during TOU-related periods across Winter months. In November and February, MURB TOU participants demonstrate overall demand reductions of 5%, which is statistically significant, with consistent reductions in demand across all TOU-related periods (Figure 46). In contrast, during March, MURB TOU customers exhibit consistent increases in demand across all TOU-related periods with an overall demand increase of 7%, which is statistically significant (Figure 46). MURB TOU participants showed inconsistent changes in demand across TOU periods, which were not statistically significant overall, in December and January.

Figure 46: A Comparison of Relative Demand Reduction (%) among Winter Months (Jan, Feb, Mar, Nov, Dec) during Specific TOU Periods



Note: 'Positive' and 'Negative' relative demand reduction (%) represent 'Reduction' and 'Increase,' respectively.

Notably, customers on the MURB TOU rate do not have a demand charge (a key distinction from the SOR General Rate). As such, measuring the impact of this rate on demand is important to ensure increases in such a metric are not occurring as there is no longer a billing penalty. Interestingly, the findings from this section indicate that overall demand decreased in MURB TOU customers with March being the only month showing a statistically significant increase.

7.2 Economic Impacts

This section presents and discusses the impact of MURB TOU Tariff on the electricity bill as well as price elasticity.

7.2.1 Change in Electricity Bills

For the assessment of the economic impacts of the MURB TOU program, the same DiD approach used to estimate load and demand impacts was applied to evaluate changes in electricity bills for MURB TOU participants. In the bill impact analysis, applicable tariffs in 2025[12] were applied in accordance with the customer type and pilot period, as summarized in Table 56.

[12] Nova Scotia Power – Tariffs: January 2025

Table 56: Tariffs Used for Evaluating the Impact of MURB TOU on Electricity Bill

Customer Type	Period	Applicable Tariff
Control	Pre-Pilot	General Tariff
Control	Pilot	General Tariff
Treatment	Pre-Pilot	General Tariff
Treatment	Pilot	MURB TOU

Table 57 presents the estimated overall bill impacts and average daily bill savings by month for MURB TOU participants during the Winter 2024/25 evaluation period. MURB TOU participants experienced an average bill saving of approximately $12 per day although it is not statistically significant. Notably, the MURB TOU rate was designed for participants to save during the non-Winter season.

Table 57: Change in Daily Electricity Bill by Month during Winter for MURB TOU Participants

Parameters	Winter Overall	Winter Months				
		January	February	March	November	December
Avg. Bill Savings ($/day)[a]	12.0 ± 30.9	-7.4 ± 32.1	56.9 ± 57.2	-1.1 ± 19.9	8.6 ± 14.1	-7.8± 36.1
Avg. Bill per Day - Pre-Pilot MURBs - TOU participants ($/day)	65	70	67	63	67	65
Relative Avg. Bill Savings (%)[a]	18.4%	-10.5%	84.9%	-1.7%	12.8%	-12.0%
Significance (p_Value≤0.05)	X	X	X	X	X	X

[a] Positive values represent 'Bill Savings', and Negative values represent 'Bill Increase'.

Notably, the effect of changes in demand on customer savings is statistically insignificant due to the effect on monthly demand (Figure 44) used for billing also being statistically insignificant.

7.2.2 Price Elasticity

NS Power evaluated participants' responsiveness to energy price under MURB TOU pricing program, focusing on estimating daily price elasticity and inter-period Substitution Price elasticity. While Daily Price Elasticity reflects the change in overall daily electricity usage caused by changes in the average daily energy price ($) per kWh, the inter-period Substitution Price elasticity reflects the MURB participants' ability to substitute more expensive electricity usage during TOU peak hours with less expensive off-peak loads, implying shifting consumption from high-price peak periods to low-price off-peak periods. It is expressed as the percent (%) change in the ratio of peak-to-off-peak average load associated with a 1% increase in the peak-to-off-peak price ratio.

NS Power's analysis reveals a daily price elasticity of -1.19 (± 1.64) during Winter, implying that for 1% increase in the average daily electricity price per kWh, the average daily electricity usage may decrease by 1.19%. The inter-period substitution elasticity is estimated at -0.032 (± 0.033), indicating that a 1% increase in the ratio of peak-to-off-peak rates might lead to a decrease of 0.032% in the peak-to-off-peak load ratio by the residential TOU customers. The daily Price Elasticity and Inter-Period Substitution Price elasticity estimated for MURBs are not statistically significant.

Findings Summary

The TVP pilot tariffs have demonstrated success in reducing load during peak periods while providing participating customers with bill savings. Both residential tariff options evaluated continue to demonstrate a strong capacity for benefiting the electrical grid and participating customers all while providing customers with choice. Positive load shift results are also emerging when evaluating the effect of the commercial rates, however, notably this appears in only the general rate participants and not in the small general rate participants. Ultimately this evaluation has provided significant evidence that the TVP Tariffs are continuing to progress towards the objective of shifting electricity usage from peak to off-peak periods/events when system utilization is lower. A summary of major findings for each tariff is presented below.

Residential TOU & CPP

- Participants continue to demonstrate statistically significant reduced load during peak periods with minimal snapback.
- For the first time, TVP combined with technology (e.g. smart thermostats) and DR (i.e. Eco Shift) was evaluated and found that significant enhancements to load reduction occurred where technology (i.e. Eco Shift + smart devices) was present.
- TOU & CPP customers who electrified their space heating reduced load during peak periods while consuming similar (TOU) and marginally more (CPP) energy throughout the year compared to those not on TVP.

Commercial TOU & CPP

- Participants for the first time have demonstrated statistically significant reduced load during peak periods. This new finding is largely attributable to improvement in methodology and increased sample sizes.
- The largest overall reductions for TOU occurred during the evening peak period in February 2025 and for CPP on the December 23 2024 evening event, when average outdoor temperatures were respectively on average −3 °C and -8 °C. These results suggest that commercial customers under the TOU & CPP tariffs can be responsive to peak periods/events during cold weather conditions. However, results for TOU peak periods differ by month, and certain CPP events did not achieve statistically significant load reductions.
- When differentiating between rate classes, Small General participants do not demonstrate responsiveness to both tariffs while the General rate class exhibits significant response to price signals.

Multi-Unit Residential Building TOU

- Despite the absence of a demand charge, MURB TOU customers did not increase their monthly demand during Winter.
- Winter energy and bill savings were positive but not statistically significant, which aligns with the rate being designed to deliver bill savings outside the Winter period.
- Overall, participants showed modest load reductions across most hours, with statistically significant reductions during evening peak periods and no evidence of snapback. Overall, these findings are directionally positive but not conclusive.

Attachment I: Riders and Tariff Structure

A summary of the TVP rate designs is included. For additional details, review the publicly available Tariff book.[13] The volumetric rates used within the billing models are summarized within this attachment in addition to visual to support understanding each TVP Tariff structure.

Riders

Although riders can change throughout a pilot Phase, to control for economic impacts associated with tariff change, a consistent tariff is used for all economic analyses. Riders are applied to all volumetric energy charges on a per kilowatt-hour basis.

Table 58: Rider Summary

TVP Group	Residential	Commercial	
Rate Class	**Domestic**	**Small General**	**General**
FAM ($/kWh)	0.00156	0.00156	0.00207
DSM ($/kWh)	0.00616	0.00778	0.00582
SCR ($/kWh)	0.00374	0.00355	0.00091

Tariffs

Although tariffs can change throughout a pilot Phase, to control for economic impacts associated with tariff change, a consistent tariff is used for all economic analyses.

Table 59: Tariff Summary (January 2025)

Domestic SOR	
Customer Charge	$19.17 per month
Energy Charge	$0.16931 per kWh
Domestic TOU	
Customer Charge	$19.17 per month
Energy Charge (Winter on-peak)	$0.33862 per kWh
Energy Charge (Winter off-peak)	$0.16931 per kWh
Energy Charge (Non-Winter)	$0.11426 per kWh
Domestic CPP	
Customer Charge	$19.17 per month
Energy Charge (on-peak)	$1.69310 per kWh
Energy Charge (off-peak)	$0.14222 per kWh
Small General SOR	
Customer Charge	$21.28 per month
Energy Charge (First 200 kWh)	$0.17567 per kWh
Energy Charge (All additional kWh)	$0.15841 per kWh
Small General TOU	
Customer Charge	$21.28 per month

[13] NS Power Tariff Book, effective October 2024. https://www.nspower.ca/docs/default-source/regulatory/nova-scotia-power-tariffs-2024-10.pdf

Energy Charge (Winter on-peak)	$0.33217 per kWh
Energy Charge (Winter off-peak)	$0.17551 per kWh
Energy Charge (Non-Winter)	$0.11731 per kWh
Small General CPP	
Customer Charge	$21.28 per month
Energy Charge (on-peak)	$1.44604 per kWh
Energy Charge (First 200 kWh off-peak)	$0.15485 per kWh
Energy Charge (All additional kWh of peak)	$0.14140 per kWh
General SOR	
Minimum Bill	$21.28 per month
Demand Charge	$10.554 per month per kW
Maximum per kWh Charge Load Factor Threshold	0.1
Energy Charge (First 200 kWh x Demand [kW])	$0.14287 per kWh
Energy Charge (All additional kWh)	$0.10990 per kWh
General TOU	
Minimum Bill	$21.28 per month
Demand Charge	$10.554 per month per kW
Maximum per kWh Charge Load Factor Threshold	0.1
Energy Charge (Winter on-peak)	$0.26243 per kWh
Energy Charge (Winter off-peak)	$0.13820 per kWh
Energy Charge (Non-Winter)	$0.09266 per kWh
General CPP	
Minimum Bill	$21.28 per month
Demand Charge	$10.554 per month per kW
Maximum per kWh Charge Load Factor Threshold	0.1
Energy Charge (on-peak)	$1.52209 per kWh
Energy Charge (first 200 kWh off-peak)	$0.11518 per kWh
Energy Charge (all additional kWh of-peak)	$0.09678 per kWh
MURB TOU	
Minimum Bill	$21.28 per month
Energy Charge (Winter on-peak)	$0.28574 per kWh
Energy Charge (Winter mid-peak)	$0.14287 per kWh
Energy Charge (Winter off-peak)	$0.12144 per kWh
Energy Charge (non-Winter on-peak)	$0.13573 per kWh
Energy Charge (non-Winter off-peak)	$0.11430 per kWh

Attachment II: ANL Hours

Table 60: Top 88 ANL Hours 2020 - 2021

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU Period AM Peak / PM Peak / Off-Peak
1	19-Feb-21	8:00 AM	1,722.6	100.0%	-8.7	AM
2	21-Jan-21	5:00 PM	1,714.4	99.5%	-3.3	PM
3	21-Jan-21	6:00 PM	1,705.1	99.0%	-3.8	PM
4	19-Feb-21	7:00 AM	1,701.6	98.8%	-8.4	AM
5	18-Feb-21	6:00 PM	1,691.4	98.2%	-6.3	PM
6	19-Feb-21	9:00 AM	1,676.5	97.3%	-8.4	AM
7	16-Feb-21	10:00 AM	1,670.9	97.0%	-3.8	AM
8	17-Dec-20	10:00 AM	1,670.8	97.0%	-9.2	AM
9	18-Feb-21	5:00 PM	1,668.1	96.8%	-5.8	PM
10	21-Jan-21	7:00 PM	1,666.3	96.7%	-4.7	PM
11	20-Feb-21	9:00 AM	1,665.4	96.7%	-7.6	Off-Peak
12	21-Jan-21	8:00 AM	1,665.2	96.7%	-11.6	AM
13	17-Dec-20	9:00 AM	1,663.6	96.6%	-9.8	AM
14	8-Mar-21	7:00 AM	1,662.7	96.5%	-8.4	AM
15	16-Feb-21	11:00 AM	1,662.5	96.5%	-3.6	Off-Peak
16	14-Jan-21	5:00 PM	1,654.0	96.0%	1.7	PM
17	17-Dec-20	12:00 PM	1,652.8	95.9%	-6.8	Off-Peak
18	21-Jan-21	9:00 AM	1,651.4	95.9%	-11.1	AM
19	18-Feb-21	7:00 PM	1,651.2	95.9%	-6.7	PM
20	16-Feb-21	9:00 AM	1,647.4	95.6%	-4	AM
21	12-Feb-21	6:00 PM	1,646.9	95.6%	-4	PM
22	17-Dec-20	11:00 AM	1,646.9	95.6%	-8.1	Off-Peak
23	14-Feb-21	10:00 AM	1,646.5	95.6%	-7.7	Off-Peak
24	23-Jan-21	9:00 AM	1,643.8	95.4%	-8.8	Off-Peak
25	17-Dec-20	8:00 AM	1,643.5	95.4%	-10.3	AM
26	16-Feb-21	12:00 PM	1,641.7	95.3%	-2.9	Off-Peak
27	22-Jan-21	12:00 PM	1,641.0	95.3%	-3	Off-Peak
28	11-Jan-21	8:00 AM	1,640.7	95.2%	-7.6	AM
29	14-Feb-21	9:00 AM	1,640.5	95.2%	-8.3	Off-Peak
30	22-Jan-21	11:00 AM	1,639.5	95.2%	-3.2	Off-Peak
31	12-Feb-21	8:00 AM	1,636.8	95.0%	-13.1	AM
32	20-Feb-21	11:00 AM	1,636.4	95.0%	-6.6	Off-Peak
33	14-Feb-21	11:00 AM	1,635.8	95.0%	-5.2	Off-Peak
34	16-Dec-20	5:00 PM	1,634.4	94.9%	-5.9	PM
35	8-Mar-21	8:00 AM	1,631.5	94.7%	-8.6	AM
36	17-Dec-20	7:00 AM	1,630.4	94.6%	-10.6	AM
37	21-Jan-21	10:00 AM	1,629.8	94.6%	-9.6	AM
38	24-Jan-21	5:00 PM	1,629.7	94.6%	-5.1	Off-Peak
39	20-Feb-21	10:00 AM	1,629.4	94.6%	-7.3	Off-Peak
40	14-Feb-21	5:00 PM	1,628.7	94.6%	-2	Off-Peak
41	21-Jan-21	8:00 PM	1,626.6	94.4%	-5.4	PM
42	23-Jan-21	5:00 PM	1,626.3	94.4%	-2.7	Off-Peak
43	1-Feb-21	9:00 AM	1,625.7	94.4%	-4.5	AM
44	28-Jan-21	5:00 PM	1,624.2	94.3%	-1.3	PM
45	21-Jan-21	7:00 AM	1,622.9	94.2%	-11.8	AM
46	1-Feb-21	6:00 PM	1,622.5	94.2%	-2	PM
47	12-Feb-21	12:00 PM	1,622.4	94.2%	-9.2	Off-Peak
48	16-Dec-20	7:00 PM	1,621.5	94.1%	-7.7	PM
49	1-Feb-21	10:00 AM	1,621.4	94.1%	-4.1	AM
50	18-Feb-21	8:00 PM	1,620.3	94.1%	-7	PM
51	12-Feb-21	5:00 PM	1,617.5	93.9%	-4.2	PM
52	23-Jan-21	10:00 AM	1,616.9	93.9%	-7	Off-Peak
53	28-Jan-21	6:00 PM	1,616.5	93.8%	-1.8	PM

Attachment II: ANL Hours

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU Period AM Peak / PM Peak / Off-Peak
54	20-Jan-21	5:00 PM	1,615.9	93.8%	-1.9	PM
55	11-Jan-21	7:00 AM	1,615.0	93.8%	-7.5	AM
56	12-Feb-21	7:00 PM	1,614.7	93.7%	-4.7	PM
57	21-Jan-21	4:00 PM	1,613.2	93.7%	-3	Off-Peak
58	1-Feb-21	5:00 PM	1,613.2	93.6%	-1	PM
59	12-Feb-21	9:00 AM	1,613.0	93.6%	-12.9	AM
60	22-Jan-21	10:00 AM	1,612.2	93.6%	-4.3	AM
61	19-Feb-21	6:00 AM	1,611.2	93.5%	-8.2	Off-Peak
62	19-Feb-21	6:00 PM	1,611.2	93.5%	-3.4	PM
63	14-Jan-21	6:00 PM	1,609.8	93.5%	1.3	PM
64	1-Feb-21	8:00 AM	1,609.1	93.4%	-4.5	AM
65	14-Feb-21	6:00 PM	1,608.7	93.4%	-2.2	Off-Peak
66	20-Feb-21	8:00 AM	1,608.4	93.4%	-7.8	Off-Peak
67	19-Feb-21	10:00 AM	1,608.2	93.4%	-7.6	AM
68	22-Jan-21	5:00 PM	1,607.3	93.3%	-2.6	PM
69	16-Dec-20	6:00 PM	1,606.8	93.3%	-7	PM
70	20-Feb-21	12:00 PM	1,606.3	93.3%	-5.8	Off-Peak
71	31-Jan-21	10:00 AM	1,604.9	93.2%	-7.4	Off-Peak
72	1-Feb-21	11:00 AM	1,603.5	93.1%	-3.5	Off-Peak
73	19-Dec-20	5:00 PM	1,602.6	93.0%	-0.8	Off-Peak
74	23-Jan-21	8:00 AM	1,601.5	93.0%	-9.1	Off-Peak
75	24-Jan-21	4:00 PM	1,599.6	92.9%	-5.4	Off-Peak
76	19-Feb-21	5:00 PM	1,598.7	92.8%	-3.3	PM
77	8-Mar-21	6:00 AM	1,597.1	92.7%	-7.9	Off-Peak
78	14-Feb-21	8:00 AM	1,596.9	92.7%	-9.6	Off-Peak
79	1-Feb-21	12:00 PM	1,596.2	92.7%	-3.2	Off-Peak
80	12-Feb-21	1:00 PM	1,596.1	92.7%	-7.8	Off-Peak
81	21-Jan-21	11:00 AM	1,595.3	92.6%	-8.2	Off-Peak
82	23-Jan-21	6:00 PM	1,594.0	92.5%	-2.7	Off-Peak
83	31-Jan-21	5:00 PM	1,593.7	92.5%	-2.5	Off-Peak
84	14-Feb-21	12:00 PM	1,591.2	92.4%	-3.8	Off-Peak
85	14-Jan-21	9:00 AM	1,589.3	92.3%	0	AM
86	7-Mar-21	7:00 PM	1,589.2	92.3%	-1.9	Off-Peak
87	13-Jan-21	5:00 PM	1,588.9	92.2%	0.6	PM
88	17-Dec-20	1:00 PM	1,588.3	92.2%	-5.9	Off-Peak

Table 61: Top 88 ANL Hours 2021 - 2022

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU Periods AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
1	6-Feb-22	7:00 PM	2,032.4	100.0%	-11.2	Off-Peak	
2	6-Feb-22	6:00 PM	2,027.3	99.8%	-10.9	Off-Peak	
3	11-Jan-22	5:00 PM	2,007.0	98.7%	-16.1	PM	
4	6-Feb-22	8:00 PM	1,993.4	98.1%	-11.3	Off-Peak	
5	27-Jan-22	8:00 AM	1,992.8	98.1%	-19.3	AM	
6	11-Jan-22	6:00 PM	1,971.9	97.0%	-16.6	PM	
7	6-Feb-22	5:00 PM	1,963.6	96.6%	-10.3	Off-Peak	
8	27-Jan-22	7:00 AM	1,957.2	96.3%	-19.5	AM	
9	27-Jan-22	9:00 AM	1,946.0	95.8%	-18.4	AM	
10	22-Jan-22	5:00 PM	1,945.6	95.7%	-8.9	Off-Peak	
11	25-Feb-22	12:00 PM	1,944.2	95.7%	-9.9	Off-Peak	
12	22-Jan-22	11:00 AM	1,938.5	95.4%	-13.5	Off-Peak	
13	22-Jan-22	12:00 PM	1,932.3	95.1%	-12.3	Off-Peak	
14	22-Jan-22	10:00 AM	1,932.0	95.1%	-15.3	Off-Peak	
15	22-Jan-22	9:00 AM	1,931.5	95.0%	-15.9	Off-Peak	

Attachment II: ANL Hours

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU Periods AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
16	12-Jan-22	8:00 AM	1,930.2	95.0%	-18.6	AM	Yes
17	7-Feb-22	8:00 AM	1,925.2	94.7%	-8.1	AM	
18	6-Feb-22	9:00 PM	1,925.2	94.7%	-12.7	Off-Peak	
19	1-Mar-22	8:00 AM	1,914.7	94.2%	-14.3	AM	
20	7-Feb-22	9:00 AM	1,914.1	94.2%	-8.4	AM	
21	25-Feb-22	11:00 AM	1,913.3	94.1%	-10.5	Off-Peak	
22	12-Jan-22	7:00 AM	1,912.9	94.1%	-19.4	AM	Yes
23	25-Feb-22	1:00 PM	1,910.5	94.0%	-10.5	Off-Peak	
24	12-Jan-22	6:00 AM	1,909.4	93.9%	-18.8	Off-Peak	
25	25-Feb-22	10:00 AM	1,908.9	93.9%	-10.7	AM	
26	22-Jan-22	4:00 PM	1,900.8	93.5%	-9.1	Off-Peak	
27	7-Feb-22	7:00 AM	1,900.4	93.5%	-10.2	AM	
28	25-Feb-22	9:00 AM	1,900.2	93.5%	-11.2	AM	
29	22-Jan-22	1:00 PM	1,898.9	93.4%	-11.6	Off-Peak	
30	11-Jan-22	9:00 AM	1,898.3	93.4%	-16.3	AM	
31	16-Feb-22	8:00 AM	1,897.2	93.3%	-14.6	AM	
32	22-Jan-22	8:00 AM	1,895.8	93.3%	-17.2	Off-Peak	
33	11-Jan-22	7:00 PM	1,888.8	92.9%	-16.8	PM	
34	11-Jan-22	10:00 AM	1,888.1	92.9%	-17.0	AM	
35	25-Feb-22	8:00 AM	1,886.8	92.8%	-11.7	AM	
36	1-Feb-22	6:00 PM	1,884.5	92.7%	-11.3	PM	
37	27-Jan-22	10:00 AM	1,884.2	92.7%	-16.9	AM	
38	27-Jan-22	5:00 PM	1,882.7	92.6%	-9.6	PM	
39	22-Jan-22	6:00 PM	1,881.0	92.6%	-9.0	Off-Peak	
40	1-Mar-22	7:00 AM	1,880.2	92.5%	-15.4	AM	
41	1-Feb-22	8:00 AM	1,877.3	92.4%	-15.3	AM	
42	25-Feb-22	2:00 PM	1,877.1	92.4%	-10.6	Off-Peak	
43	16-Feb-22	7:00 AM	1,876.9	92.4%	-15.9	AM	
44	22-Jan-22	2:00 PM	1,876.9	92.3%	-10.4	Off-Peak	
45	24-Jan-22	5:00 PM	1,872.3	92.1%	-5.2	PM	
46	11-Jan-22	4:00 PM	1,870.3	92.0%	-15.4	Off-Peak	
47	1-Mar-22	9:00 AM	1,869.2	92.0%	-13.1	AM	
48	7-Feb-22	10:00 AM	1,869.2	92.0%	-7.2	AM	
49	20-Dec-21	5:00 PM	1,869.1	92.0%	-5.8	PM	
50	12-Jan-22	9:00 AM	1,866.3	91.8%	-15.5	AM	Yes
51	1-Feb-22	9:00 AM	1,863.7	91.7%	-15.3	AM	
52	24-Jan-22	6:00 PM	1,861.8	91.6%	-5.2	PM	
53	22-Jan-22	3:00 PM	1,861.4	91.6%	-10.4	Off-Peak	
54	11-Jan-22	8:00 PM	1,860.4	91.5%	-16.8	PM	
55	11-Jan-22	11:00 AM	1,855.7	91.3%	-17.0	Off-Peak	
56	7-Feb-22	6:00 AM	1,855.6	91.3%	-11.0	Off-Peak	
57	16-Jan-22	5:00 PM	1,855.3	91.3%	-8.8	Off-Peak	
58	21-Jan-22	5:00 PM	1,854.9	91.3%	-12.4	PM	
59	1-Feb-22	7:00 PM	1,854.1	91.2%	-11.3	PM	
60	6-Feb-22	12:00 PM	1,853.6	91.2%	-13.3	Off-Peak	
61	20-Dec-21	6:00 PM	1,851.9	91.1%	-5.8	PM	
62	4-Jan-22	5:00 PM	1,851.6	91.1%	-8.2	PM	
63	1-Feb-22	5:00 PM	1,850.8	91.1%	-8.3	PM	
64	21-Jan-22	6:00 PM	1,850.7	91.1%	-13.3	PM	
65	27-Jan-22	6:00 PM	1,850.3	91.0%	-9.6	PM	
66	16-Feb-22	9:00 AM	1,850.3	91.0%	-14.6	AM	
67	16-Jan-22	8:00 PM	1,849.5	91.0%	-10.3	Off-Peak	
68	2-Feb-22	8:00 AM	1,849.4	91.0%	-13.6	AM	Yes
69	1-Feb-22	7:00 AM	1,848.5	91.0%	-14.4	AM	
70	6-Feb-22	10:00 AM	1,847.8	90.9%	-15.6	Off-Peak	
71	12-Jan-22	5:00 AM	1,847.2	90.9%	-19.5	Off-Peak	
72	27-Jan-22	6:00 AM	1,847.2	90.9%	-19.1	Off-Peak	

Attachment II: ANL Hours

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU Periods AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
73	6-Feb-22	4:00 PM	1,846.0	90.8%	-10.2	Off-Peak	
74	7-Feb-22	5:00 PM	1,845.7	90.8%	-1.0	PM	
75	6-Feb-22	9:00 AM	1,845.4	90.8%	-16.1	Off-Peak	
76	6-Feb-22	11:00 AM	1,841.3	90.6%	-14.3	Off-Peak	
77	16-Jan-22	6:00 PM	1,839.0	90.5%	-9.6	Off-Peak	
78	2-Feb-22	7:00 AM	1,838.9	90.5%	-14.8	AM	Yes
79	27-Jan-22	11:00 AM	1,835.1	90.3%	-16.9	Off-Peak	
80	16-Feb-22	6:00 AM	1,833.0	90.2%	-15.1	Off-Peak	
81	24-Jan-22	7:00 PM	1,831.0	90.1%	-6.2	PM	
82	6-Feb-22	10:00 PM	1,830.5	90.1%	-12.7	Off-Peak	
83	6-Feb-22	8:00 AM	1,829.8	90.0%	-16.2	Off-Peak	
84	16-Jan-22	7:00 PM	1,827.4	89.9%	-10.3	Off-Peak	
85	7-Feb-22	6:00 PM	1,825.0	89.8%	-1.2	PM	
86	16-Feb-22	12:00 PM	1,823.7	89.7%	-9.6	Off-Peak	
87	16-Jan22	9:00 PM	1,823.6	89.7%	-10.4	Off-Peak	
88	20-Dec-21	7:00 PM	1,823.2	89.7%	-6.4	PM	

Table 62: Top 88 ANL Hours 2022 - 2023

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU Periods AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
1	4-Feb-23	11:00 AM	2,163.1	100.0%	-23.8	Off-Peak	
2	4-Feb-23	10:00 AM	2,155.7	99.7%	-24.6	Off-Peak	
3	4-Feb-23	12:00 PM	2,146.9	99.2%	-22.5	Off-Peak	
4	4-Feb-23	9:00 AM	2,124.1	98.2%	-24.9	Off-Peak	
5	4-Feb-23	6:00 PM	2,110.7	97.6%	-16.5	Off-Peak	
6	4-Feb-23	5:00 PM	2,107.3	97.4%	-16.2	Off-Peak	
7	4-Feb-23	1:00 PM	2,102.8	97.2%	-20.8	Off-Peak	
8	4-Feb-23	8:00 AM	2,064.8	95.5%	-25.1	Off-Peak	
9	4-Feb-23	7:00 PM	2,062.8	95.4%	-16.1	Off-Peak	
10	4-Feb-23	4:00 PM	2,038.4	94.2%	-16.8	Off-Peak	
11	4-Feb-23	2:00 PM	2,037.5	94.2%	-19.3	Off-Peak	
12	4-Feb-23	8:00 PM	2,014.0	93.1%	-15.9	Off-Peak	
13	4-Feb-23	3:00 PM	2,012.4	93.0%	-18.1	Off-Peak	
14	4-Feb-23	7:00 AM	1,992.9	92.1%	-25.3	Off-Peak	
15	28-Feb-23	7:00 AM	1,952.9	90.3%	-14.4	AM	
16	26-Feb-23	8:00 AM	1,949.2	90.1%	-15.2	Off-Peak	
17	26-Feb-23	7:00 AM	1,947.9	90.1%	-15.6	Off-Peak	
18	5-Feb-23	9:00 AM	1,943.5	89.8%	-12	Off-Peak	
19	25-Feb-23	7:00 PM	1,941.0	89.7%	-13.9	Off-Peak	
20	4-Feb-23	9:00 PM	1,940.2	89.7%	-15.7	Off-Peak	
21	25-Feb-23	6:00 PM	1,933.2	89.4%	-13.3	Off-Peak	
22	2-Feb-23	7:00 AM	1,926.9	89.1%	-13.7	AM	
23	26-Feb-23	6:00 PM	1,926.5	89.1%	-8.9	Off-Peak	
24	26-Feb-23	7:00 PM	1,920.0	88.8%	-10.3	Off-Peak	
25	25-Feb-23	8:00 PM	1,919.9	88.8%	-14	Off-Peak	
26	4-Feb-23	6:00 AM	1,919.3	88.7%	-25.6	Off-Peak	
27	26-Feb-23	9:00 AM	1,911.7	88.4%	-14.1	Off-Peak	
28	5-Feb-23	8:00 AM	1,910.2	88.3%	-13.2	Off-Peak	
29	28-Feb-23	8:00 AM	1,907.7	88.2%	-12.6	AM	
30	28-Feb-23	6:00 AM	1,904.9	88.1%	-15	Off-Peak	
31	2-Feb-23	8:00 AM	1,897.7	87.7%	-12.9	AM	
32	27-Feb-23	7:00 AM	1,897.5	87.7%	-17.1	AM	
33	26-Feb-23	6:00 AM	1,893.7	87.5%	-15.9	Off-Peak	
34	12-Jan-23	8:00 AM	1,882.9	87.0%	-10.9	AM	

Attachment II: ANL Hours

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU Periods AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
35	27-Feb-23	8:00 AM	1,881.3	87.0%	-15.6	AM	
36	26-Feb-23	8:00 PM	1,875.6	86.7%	-10.9	Off-Peak	
37	26-Feb-23	5:00 PM	1,871.3	86.5%	-8.5	Off-Peak	
38	5-Feb-23	10:00 AM	1,869.3	86.4%	-9.4	Off-Peak	
39	25-Feb-23	9:00 PM	1,866.8	86.3%	-14.9	Off-Peak	
40	4-Feb-23	5:00 AM	1,866.5	86.3%	-25.9	Off-Peak	
41	12-Jan-23	7:00 AM	1,865.5	86.2%	-10.8	AM	
42	26-Feb-23	10:00 AM	1,864.9	86.2%	-12.6	Off-Peak	
43	23-Feb-23	6:00 PM	1,861.9	86.1%	-8.6	PM	
44	2-Feb-23	6:00 AM	1,858.5	85.9%	-14.8	Off-Peak	
45	5-Feb-23	7:00 AM	1,857.7	85.9%	-13.6	Off-Peak	
46	4-Feb-23	10:00 PM	1,853.9	85.7%	-15.6	Off-Peak	
47	1-Feb-23	7:00 PM	1,850.5	85.5%	-11.9	PM	Yes
48	23-Feb-23	7:00 PM	1,847.7	85.4%	-9.3	PM	
49	26-Feb-23	5:00 AM	1,844.6	85.3%	-15.5	Off-Peak	
50	1-Feb-23	6:00 PM	1,841.6	85.1%	-11.1	PM	Yes
51	1-Feb-23	8:00 PM	1,835.6	84.9%	-13	PM	Yes
52	25-Feb-23	5:00 PM	1,829.5	84.6%	-12.8	Off-Peak	
53	4-Feb-23	4:00 AM	1,827.2	84.5%	-25.9	Off-Peak	
54	2-Feb-23	9:00 AM	1,826.9	84.5%	-11.2	AM	
55	27-Feb-23	7:00 PM	1,824.7	84.4%	-10.5	PM	
56	27-Feb-23	6:00 PM	1,822.6	84.3%	-9.4	PM	
57	28-Feb-23	9:00 AM	1,821.2	84.2%	-10.1	AM	
58	26-Feb-23	11:00 AM	1,820.1	84.1%	-11.9	Off-Peak	
59	27-Feb-23	6:00 AM	1,817.9	84.0%	-17.4	Off-Peak	
60	23-Feb-23	8:00 PM	1,814.8	83.9%	-9.8	PM	
61	23-Feb-23	5:00 PM	1,814.0	83.9%	-7.8	PM	
62	24-Feb-23	8:00 AM	1,812.6	83.8%	-10.3	AM	Yes
63	4-Feb-23	3:00 AM	1,809.7	83.7%	-25.7	Off-Peak	
64	27-Feb-23	8:00 PM	1,808.7	83.6%	-12	PM	
65	12-Jan-23	9:00 AM	1,808.6	83.6%	-10.1	AM	
66	1-Feb-23	8:00 AM	1,807.6	83.6%	-14.7	AM	
67	26-Feb-23	9:00 PM	1,806.8	83.5%	-10.8	Off-Peak	
68	25-Feb-23	10:00 PM	1,804.8	83.4%	-14.7	Off-Peak	
69	4-Feb-23	2:00 AM	1,804.3	83.4%	-25.6	Off-Peak	
70	26-Feb-23	4:00 AM	1,803.6	83.4%	-15.8	Off-Peak	
71	1-Feb-23	7:00 AM	1,802.1	83.3%	-14	AM	
72	1-Feb-23	5:00 PM	1,797.4	83.1%	-9.9	PM	Yes
73	1-Feb-23	9:00 PM	1,795.8	83.0%	-13.3	Off-Peak	
74	5-Feb-23	6:00 AM	1,795.2	83.0%	-13.7	Off-Peak	
75	2-Feb-23	10:00 AM	1,794.6	83.0%	-9.2	AM	
76	27-Feb-23	9:00 AM	1,794.5	83.0%	-13.1	AM	
77	28-Feb-23	5:00 AM	1,793.7	82.9%	-14	Off-Peak	
78	11-Dec-22	5:00 PM	1,793.7	82.9%	-4.8	Off-Peak	
79	4-Feb-23	11:00 PM	1,791.1	82.8%	-15.7	Off-Peak	
80	26-Feb-23	4:00 PM	1,791.0	82.8%	-8.5	Off-Peak	
81	3-Feb-23	7:00 PM	1,790.4	82.8%	-17.2	PM	
82	4-Feb-23	1:00 AM	1,790.1	82.8%	-24.9	Off-Peak	
83	5-Feb-23	3:00 AM	1,784.6	82.5%	-15.7	Off-Peak	
84	26-Feb-23	12:00 PM	1,781.2	82.3%	-11.1	Off-Peak	
85	4-Feb-23	12:00 AM	1,778.9	82.2%	-24	Off-Peak	
86	24-Feb-23	9:00 AM	1,778.5	82.2%	-10	AM	Yes
87	12-Jan-23	5:00 PM	1,777.1	82.2%	-4.6	PM	
88	27-Feb-23	9:00 PM	1,775.1	82.1%	-12.2	Off-Peak	

Attachment II: ANL Hours

Table 63: Top 88 ANL Hours 2023-2024 Winter

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
1	21-Feb-24	7:00 AM	2047.0	100.0%	-14.6	AM	Yes
2	21-Feb-24	8:00 AM	2016.7	98.5%	-14.7	AM	Yes
3	24-Jan-24	8:00 AM	1933.5	94.5%	-13.9	AM	Yes
4	31-Jan-24	8:00 AM	1930.0	94.3%	-9.7	AM	Yes
5	21-Feb-24	6:00 AM	1919.4	93.8%	-15	Off-Peak	
6	21-Feb-24	9:00 AM	1912.0	93.4%	-13.1	AM	Yes
7	31-Jan-24	9:00 AM	1911.7	93.4%	-9.4	AM	Yes
8	24-Jan-24	7:00 AM	1897.1	92.7%	-13.5	AM	Yes
9	31-Jan-24	7:00 AM	1894.7	92.6%	-9.8	AM	Yes
10	24-Jan-24	9:00 AM	1884.1	92.0%	-12.6	AM	Yes
11	31-Jan-24	10:00 AM	1879.5	91.8%	-9	AM	Yes
12	9-Feb-24	8:00 AM	1864.6	91.1%	-7.1	AM	
13	20-Jan-24	9:00 AM	1852.8	90.5%	-8.7	Off-Peak	
14	16-Feb-24	8:00 AM	1850.9	90.4%	-8.9	AM	Yes
15	6-Jan-24	5:00 PM	1850.6	90.4%	-9.7	Off-Peak	
16	24-Jan-24	10:00 AM	1850.3	90.4%	-11.4	AM	Yes
17	9-Feb-24	7:00 AM	1844.5	90.1%	-7.1	AM	
18	20-Jan-24	5:00 PM	1841.0	89.9%	-3.9	Off-Peak	Yes
19	20-Jan-24	10:00 AM	1839.9	89.9%	-7.8	Off-Peak	
20	31-Jan-24	11:00 AM	1838.1	89.8%	-8.5	Off-Peak	
21	6-Jan-24	6:00 PM	1835.5	89.7%	-10.2	Off-Peak	
22	24-Jan-24	11:00 AM	1834.7	89.6%	-9.2	Off-Peak	
23	16-Feb-24	9:00 AM	1832.1	89.5%	-8.2	AM	Yes
24	20-Jan-24	11:00 AM	1828.6	89.3%	-6.6	Off-Peak	
25	1-Jan-24	5:00 PM	1826.0	89.2%	-5.5	Off-Peak	
26	2-Jan-24	5:00 PM	1823.9	89.1%	-3.8	PM	
27	16-Feb-24	7:00 AM	1822.2	89.0%	-10	AM	Yes
28	24-Jan-24	5:00 PM	1813.5	88.6%	-5.2	PM	Yes
29	21-Feb-24	10:00 AM	1811.0	88.5%	-10.3	AM	Yes
30	24-Jan-24	12:00 PM	1810.8	88.5%	-8.6	Off-Peak	
31	9-Feb-24	9:00 AM	1808.0	88.3%	-7	AM	
32	3-Jan-24	5:00 PM	1807.4	88.3%	-3.2	PM	
33	6-Jan-24	7:00 PM	1800.4	88.0%	-10.7	Off-Peak	
34	20-Jan-24	8:00 AM	1799.5	87.9%	-9.3	Off-Peak	
35	20-Jan-24	6:00 PM	1791.1	87.5%	-4	Off-Peak	Yes
36	30-Jan-24	5:00 PM	1790.5	87.5%	-6.9	PM	
37	30-Jan-24	6:00 PM	1789.8	87.4%	-7.5	PM	
38	1-Jan-24	6:00 PM	1788.8	87.4%	-5.4	Off-Peak	
39	20-Jan-24	4:00 PM	1785.7	87.2%	-4	Off-Peak	Yes
40	22-Feb-24	8:00 PM	1784.4	87.2%	-1.9	PM	
41	9-Feb-24	6:00 AM	1783.7	87.1%	-6.9	Off-Peak	
42	1-Jan-24	4:00 PM	1783.2	87.1%	-5.2	Off-Peak	
43	3-Jan-24	6:00 PM	1782.4	87.1%	-3.7	PM	
44	31-Jan-24	12:00 PM	1781.0	87.0%	-7.7	Off-Peak	
45	2-Feb-24	5:00 PM	1780.2	87.0%	-0.2	PM	
46	31-Jan-24	6:00 AM	1779.8	86.9%	-9.6	Off-Peak	
47	16-Feb-24	10:00 AM	1779.5	86.9%	-7	AM	Yes
48	22-Feb-24	6:00 PM	1779.1	86.9%	-1.7	PM	
49	28-Jan-24	5:00 PM	1779.0	86.9%	-0.2	Off-Peak	
50	24-Jan-24	6:00 AM	1778.8	86.9%	-13	Off-Peak	
51	2-Jan-24	6:00 PM	1777.6	86.8%	-4.2	PM	
52	20-Jan-24	12:00 PM	1776.3	86.8%	-5.4	Off-Peak	
53	28-Jan-24	6:00 PM	1776.0	86.8%	-0.4	Off-Peak	
54	24-Jan-24	4:00 PM	1775.9	86.8%	-4.8	Off-Peak	
55	26-Jan-24	8:00 AM	1774.9	86.7%	-6.1	AM	

Attachment II: ANL Hours

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
56	31-Jan-24	6:00 PM	1774.5	86.7%	-7	PM	
57	9-Jan-24	6:00 PM	1773.2	86.6%	-5.4	PM	Yes
58	31-Jan-24	5:00 PM	1772.1	86.6%	-6.5	PM	
59	26-Jan-24	12:00 PM	1772.0	86.6%	-4.4	Off-Peak	
60	26-Jan-24	10:00 AM	1770.2	86.5%	-5.3	AM	
61	3-Jan-24	8:00 PM	1769.5	86.4%	-4.5	PM	
62	30-Jan-24	7:00 PM	1768.7	86.4%	-7.9	PM	
63	22-Jan-24	8:00 AM	1768.5	86.4%	-10.7	AM	
64	26-Jan-24	5:00 PM	1767.8	86.4%	-2.4	PM	
65	22-Feb-24	7:00 PM	1766.8	86.3%	-1.8	PM	
66	6-Jan-24	8:00 PM	1766.2	86.3%	-11.1	Off-Peak	
67	9-Jan-24	5:00 PM	1765.4	86.2%	-4.7	PM	Yes
68	1-Jan-24	12:00 PM	1764.3	86.2%	-4.1	Off-Peak	
69	2-Feb-24	12:00 PM	1763.8	86.2%	-0.1	Off-Peak	
70	20-Feb-24	6:00 PM	1763.4	86.1%	-8	PM	
71	2-Jan-24	9:00 AM	1763.4	86.1%	-5.4	AM	
72	26-Jan-24	11:00 AM	1762.9	86.1%	-4.7	Off-Peak	
73	2-Feb-24	4:00 PM	1762.6	86.1%	-0.3	Off-Peak	
74	3-Jan-24	7:00 AM	1761.8	86.1%	-4.2	AM	
75	7-Jan-24	5:00 PM	1761.6	86.1%	-4.8	Off-Peak	
76	23-Dec-23	9:00 AM	1760.5	86.0%	-7.2	Off-Peak	
77	9-Jan-24	7:00 PM	1759.4	85.9%	-5.7	PM	Yes
78	1-Jan-24	7:00 PM	1759.2	85.9%	-5.5	Off-Peak	
79	24-Jan-24	1:00 PM	1759.2	85.9%	-6.9	Off-Peak	
80	2-Feb-24	1:00 PM	1759.1	85.9%	-0.1	Off-Peak	
81	3-Jan-24	7:00 PM	1758.8	85.9%	-3.4	PM	
82	1-Jan-24	1:00 PM	1758.5	85.9%	-5	Off-Peak	
83	22-Jan-24	9:00 AM	1757.7	85.9%	-9.4	AM	
84	2-Jan-24	8:00 AM	1757.5	85.9%	-6	AM	
85	16-Feb-24	6:00 AM	1757.4	85.8%	-10.7	Off-Peak	
86	26-Jan-24	9:00 AM	1756.8	85.8%	-5.6	AM	
87	23-Dec-23	8:00 AM	1755.1	85.7%	-8.3	Off-Peak	
88	28-Jan-24	7:00 PM	1754.5	85.7%	-0.4	Off-Peak	Yes

Table 64: Top 88 ANL Hours 2024 – 2025

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
1	23-Jan-25	7	2107.9	100.00%	-13.7	AM	
2	23-Jan-25	8	2093.9	99.30%	-13.8	AM	
3	6-Feb-25	8	2053.1	97.40%	-16.7	AM	Yes
4	23-Jan-25	9	2047.2	97.10%	-12.1	AM	
5	6-Feb-25	7	2039.9	96.80%	-17.3	AM	Yes
6	23-Jan-25	6	2031.7	96.40%	-13.9	AM	
7	21-Jan-25	18	2030.6	96.30%	-10.2	PM	Yes
8	21-Jan-25	17	2030.4	96.30%	-9.3	PM	Yes
9	2-Feb-25	17	2021.5	95.90%	-11.4	Off-Peak	Yes
10	2-Feb-25	18	2017.1	95.70%	-12.3	Off-Peak	Yes
11	21-Jan-25	8	2012.5	95.50%	-15.1	AM	Yes
12	10-Feb-25	8	2011.6	95.40%	-14.7	AM	
13	5-Feb-25	18	2007.8	95.30%	-13.8	PM	Yes
14	5-Feb-25	19	1996.3	94.70%	-14.5	PM	Yes
15	13-Feb-25	7	1991.7	94.50%	-12.4	AM	
16	2-Feb-25	19	1991	94.50%	-12.3	Off-Peak	Yes
17	21-Jan-25	19	1989.9	94.40%	-11	PM	Yes

Attachment II: ANL Hours

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
18	6-Feb-25	9	1985	94.20%	-14	AM	Yes
19	22-Jan-25	18	1984.5	94.10%	-13.2	PM	Yes
20	13-Feb-25	8	1984.5	94.10%	-12.2	AM	
21	29-Jan-25	7	1983.2	94.10%	-12.7	AM	
22	10-Feb-25	7	1982.5	94.10%	-14.7	AM	
23	29-Jan-25	8	1982	94.00%	-13.4	AM	
24	22-Jan-25	8	1980.7	94.00%	-15.7	AM	Yes
25	22-Jan-25	19	1976.5	93.80%	-13.9	PM	Yes
26	22-Jan-25	17	1975.1	93.70%	-12.2	PM	Yes
27	17-Jan-25	8	1969.4	93.40%	-9.4	AM	
28	10-Feb-25	9	1968.8	93.40%	-13.2	AM	
29	21-Jan-25	7	1967.9	93.40%	-14.9	AM	Yes
30	3-Feb-25	7	1967.8	93.40%	-9.5	AM	
31	13-Feb-25	6	1965.4	93.20%	-13	AM	
32	5-Feb-25	20	1964.6	93.20%	-14.3	PM	Yes
33	22-Jan-25	20	1962.2	93.10%	-14.4	PM	Yes
34	21-Jan-25	9	1958.1	92.90%	-14.3	AM	Yes
35	16-Jan-25	17	1957.3	92.90%	-6.7	PM	
36	3-Feb-25	8	1952.4	92.60%	-10	AM	
37	31-Jan-25	8	1951.2	92.60%	-14.9	AM	
38	21-Jan-25	20	1945.3	92.30%	-10.9	PM	Yes
39	12-Feb-25	20	1945	92.30%	-10.6	PM	
40	31-Jan-25	7	1943.7	92.20%	-15.7	AM	
41	13-Feb-25	9	1941.6	92.10%	-11.2	AM	
42	22-Jan-25	7	1938.8	92.00%	-14.6	AM	Yes
43	2-Feb-25	20	1934.5	91.80%	-12.1	Off-Peak	Yes
44	17-Jan-25	7	1933.5	91.70%	-10.7	AM	
45	12-Feb-25	19	1931.8	91.60%	-9.9	PM	
46	23-Jan-25	10	1930	91.60%	-10.3	AM	
47	5-Feb-25	17	1929.8	91.50%	-13.5	PM	Yes
48	6-Feb-25	6	1928.7	91.50%	-16	AM	Yes
49	29-Jan-25	9	1928.4	91.50%	-12.1	AM	
50	4-Mar-25	7	1925.4	91.30%	-11.9	AM	Yes
51	16-Jan-25	18	1924.6	91.30%	-6.9	PM	
52	2-Feb-25	16	1922.6	91.20%	-10.2	Off-Peak	Yes
53	11-Feb-25	8	1920.1	91.10%	-15.9	AM	
54	10-Feb-25	18	1919.1	91.00%	-6.4	PM	
55	17-Jan-25	9	1917.8	91.00%	-9.2	AM	
56	22-Jan-25	9	1916.2	90.90%	-15.4	AM	Yes
57	12-Feb-25	18	1915.6	90.90%	-9.4	PM	
58	2-Feb-25	9	1915.4	90.90%	-17.2	Off-Peak	Yes
59	10-Feb-25	17	1912.4	90.70%	-5.8	PM	
60	23-Dec-24	17	1912	90.70%	-9.2	PM	Yes
61	11-Feb-25	7	1911.7	90.70%	-16.2	AM	
62	16-Jan-25	19	1909.2	90.60%	-7	PM	
63	23-Jan-25	5	1908.5	90.50%	-13.6	AM	
64	10-Feb-25	20	1908.2	90.50%	-7.8	PM	
65	10-Feb-25	10	1907.2	90.50%	-11.9	AM	
66	29-Jan-25	10	1907	90.50%	-10.8	AM	
67	21-Jan-25	16	1906	90.40%	-9	PM	Yes
68	23-Dec-24	18	1904.8	90.40%	-10.3	PM	Yes
69	14-Jan-25	17	1902	90.20%	-2.2	PM	
70	12-Feb-25	21	1901.3	90.20%	-11.6	PM	
71	21-Jan-25	10	1900	90.10%	-13.1	AM	Yes
72	5-Feb-25	21	1899.7	90.10%	-14	PM	Yes
73	22-Dec-24	17	1899.3	90.10%	-11.7	Off-Peak	Yes
74	23-Jan-25	1	1899	90.10%	-14.9	AM	

Attachment II: ANL Hours

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
75	23-Jan-25	0	1891.8	89.70%	-15	AM	
76	29-Jan-25	11	1891.5	89.70%	-9.7	AM	
77	1-Feb-25	9	1891.3	89.70%	-9.7	Off-Peak	
78	10-Feb-25	21	1891.3	89.70%	-10.1	PM	
79	23-Dec-24	19	1891	89.70%	-10.6	PM	Yes
80	13-Feb-25	5	1891	89.70%	-13.1	AM	
81	10-Feb-25	13	1890.7	89.70%	-7.2	PM	
82	16-Jan-25	16	1889.8	89.70%	-6.7	PM	
83	29-Jan-25	6	1889.1	89.60%	-12.9	AM	
84	10-Feb-25	12	1887.1	89.50%	-8.7	PM	
85	10-Feb-25	19	1885.6	89.50%	-6.8	PM	
86	10-Feb-25	11	1885.3	89.40%	-9.6	AM	
87	6-Feb-25	10	1885.1	89.40%	-11	AM	Yes
88	21-Jan-25	23	1884.8	89.40%	-11.2	PM	Yes

Attachment III: Methodology

The methodology for control group selection, tariff impact, and the sub-models that support these evaluations are contained within this section. To be comprehensive, all regression models are included in this section; however, when variables are consistent between regression formulas, they are not repeatedly redefined.

III.1 Datasets

The datasets used in this evaluation are summarized along with any relevant processes and cleaning steps.

Advanced Metering Infrastructure

The necessary AMI 15-minute interval data are aggregated to eight 24-hour load profiles for control group selection and hourly data for regression modelling (treatment and control). Cleaning steps specific to control group selection (Table 68) and regression modelling are defined within their respective sections.

Demographic

Environics Analytics is a Canadian data and analytics company that provides population, demographic and geographic datasets, along with analytical tools and consulting services used for market analysis and planning. For TVP, Environics Analytics provides current-year demographic data, including de-identified, aggregated and anonymized information such as income, population, household counts, diversity, etc. This represents the predominant demographic profile of households assigned to a postal code or a dissemination area. Environics Analytics is certified under the ISO's Privacy by Design standard and follows applicable Canada's privacy laws and industry best practices for protecting personal information.

Data used from Environics comes without a margin of error and is used as such despite uncertainty that arises from such aggregations. As a result, conclusions from this data should be treated as indicative, and directional in nature only, even when results are statistically significant.

Environmental

This evaluation uses Environment and Climate Change Canada temperature data[14] to control for the effect of heating degree days in the regression model and to determine CPP reference days. The temperature data is mostly without gaps, however, to eliminate gaps in weather data, three cleaning steps are performed in series for the eight weather stations.

Step 1 (Airports only): Each weather station has primary and alternative weather datasets defined by its climate ID. Airports have multiple primary weather datasets, therefore if one Climate ID has missing data the other will solely be used, if both are available the average is used.

Step 2 (All weather stations): If no primary weather data exists for a station, the nearest alternative weather station is used. The alternative weather station can be the nearest Primary weather station and/or an alternative weather station that was added to the dataset to serve only as an alternative.

[14] Environment and Climate Change Canada. (n.d.). *Historical Data – Past Weather and Climate*. Retrieved July 3, 2025, from Environment and Climate Change Canada website: https://climate.weather.gc.ca/historical_data/search_historic_data_e.html

In cases where multiple alternative data sources exist, the average is used. Table 65 provides a complete list of primary weather stations and the designated alternatives.

Table 65: Weather Station and Climate

Site	Station Name	Climate ID	Classification	Alternative Site
1	HALIFAX STANFIELD INT'L A	8,202,251	Primary	5
2	HALIFAX STANFIELD INT'L A	8,202,249	Primary	5
3	KENTVILLE CDA CS	8,202,810	Primary	1,2
4	NAPPAN AUTO	8,203,702	Primary	1,2
5	SHEARWATER RCS	8,205,092	Primary	1,2
6	SYDNEY A	8,205,703	Primary	-
7	SYDNEY A	8,205,701	Primary	-
8	TRACADIE	8,205,895	Primary	6,7,12,13
9	WESTERN HEAD	8,206,240	Primary	1,2,10,11
10	YARMOUTH A	8,206,495	Primary	11
11	YARMOUTH A	8,206,496	Primary	10
12	COLLEGEVILLE AUTO	8,201,001	Alternative	-
13	PORT HAWKESBURY	8,204,495	Alternative	-

Note: 'A' in Station Name identifies airport weather station.

Step 3: If there are still gaps in temperature data for the eight primary weather stations, a Makima cubic Hermite interpolation (i.e. a modified cubic spline interpolation) is used to fill in any remaining missing temperature data points.

Once data cleaning and interpolations step have been complete, temperature data from the nearest primary weather station to each treatment and control customer is mapped based on proximity using latitude and longitude coordinates.

Energy Savings Programs

E1 program participation[15] and evaluation reports[16] are used for control group selection balancing. Refer to Attachment III: Methodology (section III.2.4 E1 Program Balancing) for additional details.

E1's Eco Shift program identifies customers with specific devices (e.g. smart thermostats, managed electric vehicle (EV) charging, and residential batteries). In brief, the Eco Shift is an event-based DR program that controls these behind the meter technologies with the purpose of lowering load during these event periods. Notably, while the technology is only controlled by the Eco Shift program during events, these devices are permanently installed and, in some cases, can be independently controlled by the homeowner (e.g. smart thermostats). This data is used to determine if combining TVP with Eco Shift improves load impacts. Results relevant to Eco Shift are contained within the load impact in Sections 3.1 (for TOU) and 4.1 (for CPP).

[15] Provided to NS Power for the sole purpose of control group selection balancing for the TVP evaluation.

[16] EfficiencyOne, 2020-2024 DSM Evaluation Reports. NSEB Matter numbers M10056, M11071, M11630, M12186.

Property

Property Valuation Services Corporation (PVSC) is an independent, not-for-profit organization in Nova Scotia responsible for assessing all property in the province under the Nova Scotia Assessment Act. For TVP, PVSC data provides the year built, living area and housing style data. Data is mapped to individual customers using latitude and longitude data.

System & Wind Load

System load and wind load used for adjusted net load calculations are respectively sources sourced from NS Power's publicly available OASIS dataset[17] and NS Power's internal dataset.

III.2 Control Group Selection

Control group selection in Phase 4 is comprised of four modified elements that will improve the evaluation relative to previous iterations. Changes are summarized in Table 66.

Table 66: Summary of Changes to Control Group Methodology[18]

Previous Method	New Method	Projected Benefit
Neighbourhood criteria based on feeder and postal code combination	Neighbourhood criteria to be based on region (i.e. Cape Breton, Northeast, Metro, and West)	Increased pool of potential Control to Treatment matches will improve load similarity metric
Heating classification applied after initial ten control group selection candidates chosen.	Heating classification will be included in control group selection process when selecting initial ten control candidates.	Improved load similarity metric in final Control to Treatment matches by heating segment
Does not control for Eco Shift participation.	Include Eco Shift participation in control group selection process	New metric: Quantify the additional impact of combining Eco Shift with TVP.
E1 program participation balancing completed post control group selection	E1 programming will be included in control group selection process.	Improved load similarity metric in final Control to Treatment matches and streamlined control group selection process

The control group is composed of non-TVP participant customers that have the best 'Similarity Metric' relative to each individual treatment customer, as defined by equation (1), while ensuring all

[17] NS Power, OASIS, hourly total net Nova Scotia load. https://www.nspower.ca/oasis/monthly-reports/hourly-total-net-nova-scotia-load

[18] Please refer to Appendix E, Attachment 3, page 23.

evaluated sub-group combinations (Table 67) have acceptable group level load similarity and balancing for E1 programming.

Table 67: Control Group Selection TVP Sub-Groupings

Sub-Group	Possible Sub-Groupings (784 Possible Combinations)
TVP Tariff	TOU / CPP / MURB TOU
Rate Class	Domestic / Small General / General
Cohort	Cohort 1 / Cohort 2 / Cohort 3 / Cohort 4
Neighbourhood	West / Metric / Northeast / Cape Breton
Heating Classification	Steady Electric / Steady Non-Electric / Electrified / De-Electrified
Eco Shift Participation	Yes/No

This bottom-up approach of individually matching treatment and control group customers at the most granular sub-group level ensures the best possible method to quantify effects at the various subgroupings without sacrificing accuracy when sub-groups (e.g. TOU Electrified or TOU Cohort 3) are aggregated to larger groupings (e.g. TOU).

The load similarity metric calculation is determined from aggregate AMI data for each treatment customer with respect to all potential control group candidates. The AMI data will be aggregated to average hourly interval consumption and peak hourly interval consumption during Winter and non-Winter (April to October), weekdays and weekends, creating two sets of 96 data points per customer. This aggregated AMI data is then used to calculate a new two-dimensional Euclidean distance similarity metric 'SM_{AMI}' as defined by equation (1).

$$SM_{AMI} = \frac{\sum_{i=1}^{96} \frac{|Tavg_i - Cavg_i|}{Tavg_i} + \sum_{i=1}^{96} \frac{|Tpeak_i - Cpeak_i|}{Tpeak_i}}{2} \quad (1)$$

Where:

$\boldsymbol{i}$ are datapoints corresponding the 24 hours in both seasons (Winter/non-Winter) and day types (weekend/weekday) for a total of 96 different combinations.

$\boldsymbol{Tavg_i}$ is the average load of the treatment customer during datapoint i.

$\boldsymbol{Cavg_i}$ is the average load of the potential control customer during datapoint i.

$\boldsymbol{Tpeak_i}$ is the maximum load of the treatment customer occurring during datapoint i.

$\boldsymbol{Cpeak_i}$ is the maximum load of the potential control customer occurring during datapoint i.Once calculated for all potential control group customers, the top 10 per treatment customer (i.e. lowest 10 similarity metrics) for each subgroup (i.e. TVP Tariff, Rate Class, Cohort, Region, Heating Classification, and Eco Shift), are balanced for E1 program participation to control for any load altering programs administered by E1.

In addition to the processes defined within this section, cleaning steps are performed to remove customers with insufficient data from the treatment group and/or the control group; refer to Table 68.

Table 68: Treatment and Control Interval Data Cleaning Steps

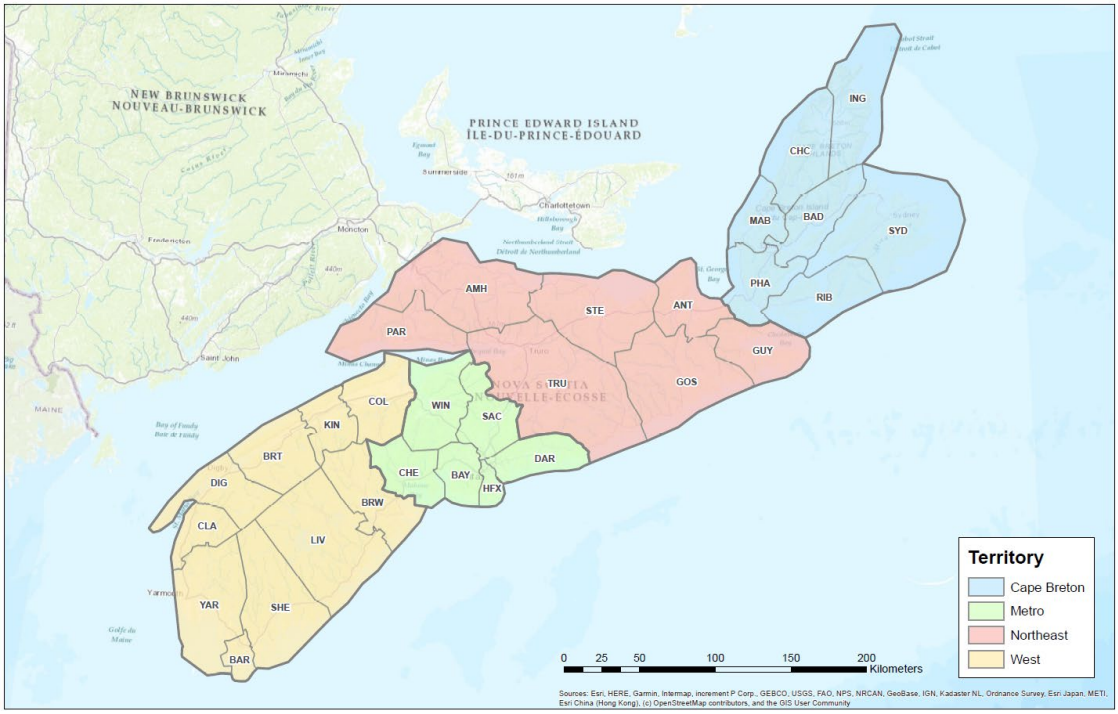
Step	AMI Data Selection – Cloud scale query to retrieve AMI data for treatment and all potential control customers
A	Limit to data to the pre-pilot period for each cohort respectively.
B	Limit to only data which is stamped as "actual"[19]
C	Only customers with over the air (OTA) billing enabled are considered.
D	Remove all seasonal and net metering customers (control only).
E	Limit to Domestic, Small General and General rate class customers.
Step	**Control Group Selection**
A	Limit list to customers with ≥ 50% of necessary data.
B	Limit list of treatment customers to those in the pilot for a minimum of 60 days.

III.2.1 Neighbourhood Criteria

The intent of using neighbourhood criteria is primarily to choose control customers who have similar housing types and environmental weather patterns relative to treatment customers. In previous evaluations, the volume of AMI data that could be processed was limited by local machine computations, as such, the previous methodology sacrificed a larger control group selection pool for the distinct advantage in minimizing the volume of AMI data. However, given the requirement to analyze distinct heating classifications, a broader control selection pool is required. To meet this requirement, the new method which analyzes all AMI data with a territory for each control group selection cohort is enabled by cloud scale analytics, which became part of NS Power's analytical toolbelt in 2024. The neighbourhood criteria territories are shown in Figure 47.

[19] AMI interval reads can either be classified as "actual" or "estimated". Actual reads are measured consumption were estimated reads are based on historical usage. Estimate reads are rectified for billing purposes however these datapoints are not overwritten in the cloud scale analytics platform where the data is retrieved.

Figure 47: Map of Nova Scotia by Control Group Selection Neighbourhood Criteria Territories

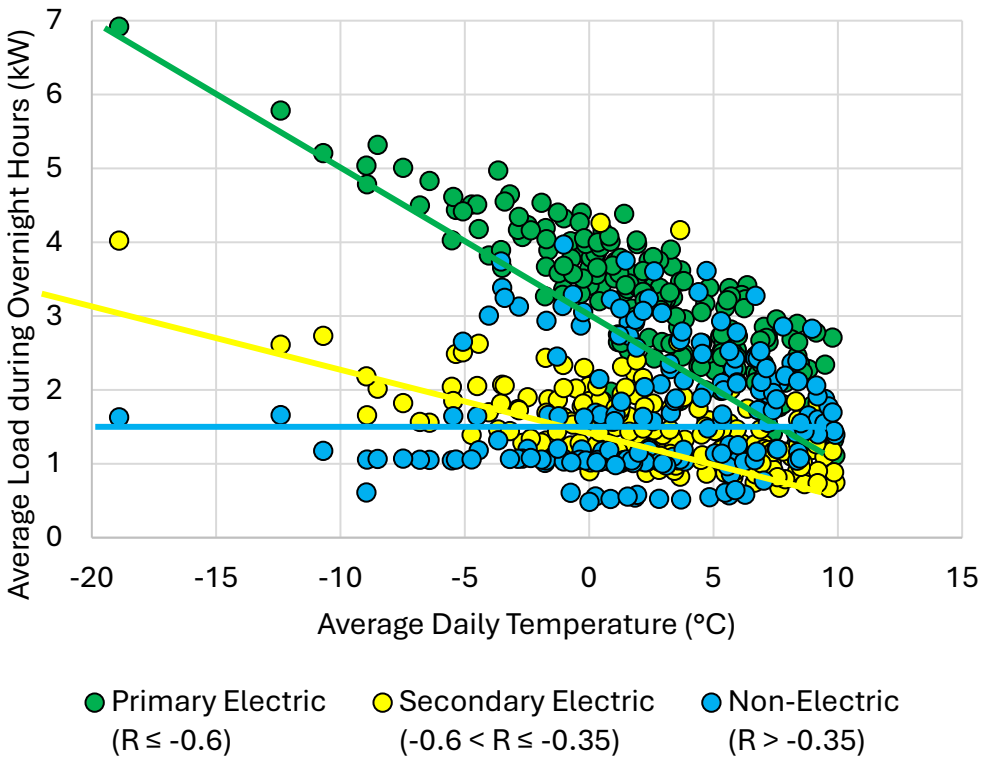


Note that depot names are included in Figure 47, although for control group selection only the four territories are used. For example, a treatment customer from Metro, must be matched to a control customer also from Metro. The benefit of this proposed change includes simplification of control group selection process by removing the need for billing data by directly accessing AMI data for large (100k+ population groups).Using this method, the potential control group population of AMI data is increased significantly, which will improve the match precision and enable the addition of heating classification & Eco Shift to control group selection.

III.2.2 Heating Classification

Customers are first classified into three categories (Primary, Secondary, Non-Electric) based on their electricity consumption as visualized in Figure 48.

Figure 48: Example of Heating Correlation Model Classifications



The heating classification method uses AMI and nearby weather station temperature data for individual premises to classify space heating types. AMI data was restricted to overnight hours (i.e. 10 PM – 5 AM) where the average daily temperature is below 10 °C. The model operates on the principle that the more negatively correlated a customer's consumption is to temperature (i.e. consumption increases while temperature decreases) the likelier they are to be heated with electricity. Using the correlation coefficient, 'R', a customer would be classified as secondary electric (-0.6<R≤-0.35) or primary electric (-0.6≤R).[20]

The model's output is simplified for the purposes of this evaluation to consider all customers as primary or secondary electric to 'electric' (i.e. R≤-0.35). Additionally, a mean consumption threshold during the top 20 consumption days of 0.5 kW or greater was required. This threshold is applied to avoid classifying customers with significantly low consumption during cold days regardless of correlation coefficient. Both metrics must be satisfied to be classified as electric, refer to Table 69.

Table 69: Electric Space Heating Classification Requirements

Mean load during top 20 consumption days	R≤-0.35	R>-0.35
< 0.5 kW	Non-Electric	Non-Electric
≥ 0.5 kW	Electric	Non-Electric

[20] The correlation coefficient, R, was calculated between Average Daily Temperature (°C) and Average Power Consumption during Overnight Hours (kW) to quantify the strength and direction of the linear relationship between the two variables.

The classification was completed in the pre-pilot and pilot period for each participant and potential control customer to create four heating classifications; refer to Table 70.

Table 70: Heating Classification Definition

Heating Classification	Pre-Pilot	Pilot Period
Steady Electric	Electric	Electric
Steady Non-Electric	Non-Electric	Non-Electric
Electrified	Non-Electric	Electric
De-electrified	Electric	Non-Electric

The heating classification is used to ensure treatment and control customers are from the same classification during control group selection.

Notably, the heating classification methodology and its application to the TVP evaluation has been modified in each Phase of the evaluation, this progression is documented in Attachment IV: Historical Methodological Changes.

III.2.3 Eco Shift

A new addition to the TVP evaluation included the effect of combining the Eco Shift administered by E1 with TVP. Control group selection for these customers was incorporated into this evaluations methodology to ensure that Treatment to Control pairings for Eco Shift sub-groups had satisfactory similarity metrics. To facilitate control group selection, a list of known Eco Shift participants was provided to NS Power by E1. Customers in both TVP + Eco Shift and TVP by itself were limited to a control group selection pool of non-Eco Shift participants while adhering to all other control group selection criteria.

To ensure the effect of Eco Shift and TVP are understood properly, NS Power requested a list of Eco Shift events from E1, provided in Table 71. Notably nearly all Eco Shift events are CPP events as the programs were aligned through collaborative efforts between E1 and NS Power.

Table 71: List of Eco Shift Events and Their Corresponding Starting/Ending Times, with Event Participant Distinction (All Eco Shift vs. CPP Only)

Participants [a]	Eco Shift Event Date	Event Hour Window	Is CPP Event?	Is Weekend?
All	04-Dec-2024	5 PM – 9 PM	✓	x
CPP	15-Dec-2024	5 PM – 9 PM	✓	✓
All	20-Dec-2024	7 AM – 11 AM	✓	x
CPP	22-Dec-2024	5 PM – 9 PM	✓	✓
All	23-Dec-2024	5 PM – 9 PM	✓	x
CPP	23-Dec-2024	7 AM – 11 AM	✓	x
All	21-Jan-2025	5 PM – 9 PM	✓	x
All	22-Jan-2025	7 AM – 11 AM	✓	x
CPP	02-Feb-2025	5 PM – 9 PM	✓	✓
All	05-Feb-2025	5 PM – 9 PM	✓	x
All	06-Feb-2025	7 AM – 11 AM	✓	x
All	12-Feb-2025	5 PM – 9 PM	x	x

[a] Where "All" designates the event applies to all Eco Shift participants regardless of whether they are on a standard offer rate (SOR), TOU, CPP or any other tariff. "CPP" defines events that are specific to those in CPP and Eco Shift to maximize Eco Shift efficacy during CPP event periods.

III.2.4 E1 Program Balancing

Treatment and control customer participation in E1 programs (Home Energy Assessment, Green Heat, Appliance Retirement, Efficient Product Installation, Small Business Energy Solutions, Business Energy Rebates, and Custom) are balanced using this process to mitigate confounding effects of EOne programs on TVP results. It should be noted Eco Shift is balanced separately with its own control sub-group as indicated in Table 67.

i. The lowest similarity metric (equation (1)) is prioritized with alternates continuously chosen until the associated E1 energy savings in both the potential control and treatment are equal for each subgroup. To complete this balancing, E1 has provided NS Power with customer participation in each of these programs from 2021 through 2024. Using the list, the effect for E1 programming on energy consumption is controlled for using the following steps (i. through v.). Customers in the treatment and potential control group selection pool are mapped to their corresponding E1 programs (if any).

The energy savings filed for each of the program in the year it was administered[21] is average per participant and adjusted for line loss factors. These program savings are allocated to each customer in treatment and potential control based on program year and TVP cohort using equation (2) and Table 72.

$$E1\ Energy\ Savings = ProgramSavings_y * Factor_{y,c} \quad (2)$$

[21] EfficiencyOne, 2020-2024 DSM Evaluation Reports. NSEB Matter numbers M10056, M11071, M11630, M12186.

Table 72: Phase 4 E1 Program Year and TVP Cohort Savings Correction Factor

E1 Program Year (y) / TVP Cohort (c)	2021	2022	2023	2024
Cohort 1	0.67	1	1	0.75
Cohort 2	0	0.67	1	0.75
Cohort 3	0	0	0.67	0.75
Cohort 4	0	0	0	0.42

For example, if a Cohort 2 TVP customer or the potential control customer for this TVP participant had a home energy assessment completed in 2022, a factor of 0.67 would be multiplied by the program savings for that program in that year (4344 kWh annually) to yield a E1 energy savings of 2,910 kWh annually in Phase 4.

The savings correction factor logic is to account for customers participating in an E1 program part way through either the pre-pilot or pilot period. For instance, continuing with the example above, a Cohort 2 TVP participant's pre-pilot period was from November 1, 2021 to October 31, 2022, thus 10 months of the pre-pilot was in 2022. If they participated in an E1 program in 2022, some of the pre-pilot data would be affected by the E1 program. Since NS Power does not know during which month the customer participated in the Home Energy Assessment, it is assumed in this method that participation occurred in the middle of the year (i.e. July 1, 2022). Using this assumption, eight of the twelve months (November 2021 to June 2022 / 67% of control year) were unaffected by the E1 program, and as such will not be fully included in pre-pilot AMI data and should be accounted for in control group balancing to not bias the pilot period results.

ii. The total E1 programming energy savings for the treatment group and the corresponding group of top control candidates, determined by similarity metric are evaluated and compared.

iii. If the treatment group displays higher or lower E1 annual energy savings relative to the initial control group (first pick), alternative control group customers are selected from the "top ten control" match with higher or lower E1 energy savings until the balance is zero or near zero for the control group.

iv. Once a balance of zero, or near zero energy savings between treatment and control is achieved, this process is repeated for all control sub-group combination (i.e. TVP Tariff, Rate Class, Region, Heating Classification, Eco Shift Participation).

The equation used to define where a control and treatment group have balanced the expected energy savings due to EOne is defined by equation (3).

$$E1\ Balance\ Acccuracy = \left(1 - \frac{|T_{savings} - C_{savings}|}{T_{savings}}\right) x100\% \quad (3)$$

Where:

$\boldsymbol{T_{savings}}$ is the sum of annual treatment group E1 program savings

$\boldsymbol{C_{savings}}$ is the sum of annual control group E1 program savings

III.2.5 Match Accuracy

Once a final control group has been established, the quality of the control group selection match is defined by the 'Match Accuracy', refer to equation (4).

$$Match\ Accuracy = \left(1 - \frac{\overline{|T_t - C_t|}}{\overline{T}}\right) x100\% \quad (4)$$

Where:

$\boldsymbol{T_t}$ is the treatment power at time 't' where t ranges from 1 to 96

$\boldsymbol{C_t}$ is the control power at time 't' where t ranges from 1 to 96

$\boldsymbol{\overline{T}}$ is the average of all 96 power datapoints for the treatment group

III.2.6 CPP Reference Days

Although the regression model controls for time synchronous (i.e. zero hour lag-lead) temperature effects in the form of heating degree days (HDD), it is critical to find reference days with similar temperature profiles to the event day to minimize the variable bias in the results that would be caused by lagging temperature effect on customer consumption. Notably, the methodology for reference day selection has remained consistent for TVP throughout all evaluations.

Reference days are used as control period days for both treatment and control TVP customers (i.e. Pilot Period = 0) in the regression. Reference days cannot be other completed or cancelled CPP event days or holidays[22]. Additionally, reference days must be within +/- 20 days of the event day (Criteria A) and be of the same weekday type (Criteria B).

There are three weekday types:

Type 1: Monday or Friday (MF)

Type 2: Tuesday, Wednesday, Thursday (TWT)

Type 3: Saturday or Sunday (SS)

The three weekday types are used to find days where customers have similar consumption patterns. Grouping residential electricity consumption days into categories like MF, TWT, and weekends (SS) reflects common behavioral patterns that influence energy use. These groupings help control for behavioural patterns that effect energy consumption.

While Criteria A and B define which days can be potential CPP reference days, they do not quantify which of these days are the best for TVP regression. To determine the best CPP reference day for each event by weather station, temperature for the 24 hours pre-event (Criteria C) and the temperature at the beginning of the peak event (Criteria D) are compared with potential reference days and ranked according to similarity using the Euclidean distance method. The 24-hour Euclidean distance measurement (Criteria C) is defined by equation (5).

[22] Critical Peak Pricing Tariff, "Critical Peak Event Procedure," Condition (1) definition of 'holiday,' page 2.

$$Criteria_C = \sqrt{\sum_{i=0}^{i=23}(E_i - R_i)^2} \quad (5)$$

Where:

$\boldsymbol{i}$ defines the hours before the start of the CPP event. For example, if the event starts at 7 AM, $i = 0$ at 7 AM for both the event and reference data.

$\boldsymbol{E_i}$ is the event day temperature at hour i

$\boldsymbol{R_i}$ is the reference day temperature at hour i

Using the $\mathrm{Criteria_C}$ metric, each candidate reference day is assigned a rank in ascending order, denoted as $\mathrm{Rank_C}$. Specifically, the reference day with the minimum value of $\mathrm{Criteria_C}$ is assigned $\mathrm{Rank_C}$ = 1, the day with the second-lowest value is assigned $\mathrm{Rank_C}$ = 2, and so forth, such that lower values of $\mathrm{Criteria_C}$ correspond to higher (i.e., better) rankings.

$\mathrm{Criteria_D}$ is calculated by taking the absolute difference between the temperature at the starting time of the event on the event day (E_0) and all potential Reference days (R_0). $\mathrm{Criteria_D}$ is then ranked in the same manner to $\mathrm{Criteria_C}$ to form $\mathrm{Rank_D}$. The rankings from both $\mathrm{Criteria_C}$ & $\mathrm{Criteria_D}$ are combined using equation (6) to form $\mathrm{Rank_{CD}}$.

$$Rank_{CD} = \sqrt{Rank_C^2 + Rank_D^2} \quad (6)$$

This method weighs the ranking of a 24-lagging temperature and the concurrent temperature at the start of the event to determine the most suitable reference day for each CPP event for each weather station. In many cases, the best reference day for each event is the same for all weather stations; however, occasionally, the reference day for a given event day varies between weather stations, especially for weather stations on opposite sides of the province where temperatures can differ more significantly. For additional clarity, refer to the results of this year's CPP reference day model in Table 8 (section 2.4 CPP Reference Days).

III.3 Regression Models

The regression models are divided into three sections, Residential TOU & CPP, Commercial TOU & CPP and MURB TOU.

Notably, these regression models utilize hourly AMI data on a per-customer basis. This shift from previous evaluation reports, combined with increased sample sizes in Phase 4, has resulted in smaller margins of error (MoE) relative to earlier TVP evaluation reports.

III.3.1 Residential TOU & CPP

This section presents the methodology used to determine the load, usage, and economic impact of the residential TOU and CPP tariffs. The estimates for load and economic impacts are rounded and reported according to the number of significant figures supported by the margin of error at the 90% confidence level to avoid implying false precision. Although some values are reported with three significant figures, most are presented with two significant figures.

III.3.1.1 Load & Usage Impact Regression Model

The regression model used for load and usage impacts is presented in equation (7).

$$Load_{it} = \beta_0 + \beta_1.Treatment_i + \beta_2.PilotPeriod_t + \beta_3.(Pilot \times Treatment)_{it} + \beta_4.HDD_{it} + \beta_5.(Pilot \times Treatment)_{it}.HDD_{it} + \varepsilon_{it} \quad (7)$$

Where:

***Load**$_{it}$* is the average load in 'kW' by customer '*i*' for the time period of '*t*' (e.g. each TOU peak period of 4 hours or CPP event period of 4 hours). For usage impact, ***Load**$_{it}$* is replaced by ***Energy**$_{it}$* which is the energy consumption in 'kWh/day' by customer '*i*' for the time period of '*t*'.

β_0 is the intercept (the average load that is independent of any of the independent variables).

***Treatment**$_i$* is a binary variable (dummy variable) that equals 0 for control group customers and 1 for treatment group customers under TOU or CPP tariffs.

PilotPeriod**$_t$* is a binary variable (dummy variable) that equals 0 for the period before TOU Tariff is in effect, and equals 1 during the pilot period when the TOU tariffs are in effect. For CPP Tariff, PilotPeriod is replaced by ***DayType where it equals 1 for CPP events and equals 0 for Reference days.

***(Pilot×Treatment)**$_{it}$* is a binary variable that equals 1 only for the treatment customers during pilot period; otherwise, it equal 0.

***HDD**$_{it}$* is a variable linked to the heating degree-day (with a balance temperature of 12 °C) value at time *t* and the weather station associated with weather station of premise *i*. This variable is generally the average HDD minus a fixed value determined by mean of the average HDD values.

β_1 is the coefficient describing the correlation between being a treatment customer and the average load.

β_2 is the coefficient describing the correlation between being during the pilot period and the average load.

β_3 is the coefficient describing the correlation between being a treatment customer during pilot period and the average load.

β_4 is the coefficient describing the correlation between HDD and the average load.

β_5 is the coefficient describing the correlation between *Pilot*×*Treatment*, *HDD* and the average load.

$\beta_4+\beta_5\times$***HDD*** represents the effect of TVP on average Load.

ε_{it} is the regression error.

For daily electricity usage impact analysis, ***Load**$_{it}$* in equation (7) is replaced by ***Energy**$_{it}$* which is the energy consumption in **kWh/day** by customer '*i*' at time '*t*'.

TVP customers in Eco Shift will be evaluated from December 1, 2024 – February 28, 2025. For comparison, TOU and CPP customers that are not in Eco Shift will be evaluated within the same time-period. Relative to the TVP regression model without Eco Shift, two additions have been made. The first, a binary variable that represents TVP and Eco Shift enrolment during the pilot period. The

second, the addition of a random intercept, changing the model from a fixed effects to mixed-effects model. Given the relatively small participant count of Eco Shift with TVP (TOU = 115 , CPP = 94) and heterogeneity of baseload and device type (e.g. smart thermostats, managed EV charging), a careful selection process between Fixed Effect and Mixed Effect modeling was considered, where the choice of the analysis approach can affect the precision and reliability of the estimated TVP program impacts. A similar comparison for Commercial customers is accounted for in Attachment V: Validation of Mixed Effects Regression, although this is a different TVP group, the principles discussed for commercial participants relate to the residential TVP x Eco Shift participants, as such a mixed effect model was deemed to be more accurate. Refer to equation (8) for the complete TVP x Eco Shift regression model.

$$Load_{it} = (\beta_0 + u_i) + \beta_1.Treatment_i + \beta_2.PilotPeriod_t + \beta_3.(Pilot \times Treatment)_{it} + \beta_4.HDD_{it} + \beta_5.(Pilot \times Treatment)_{it}.HDD_{it} + \beta_6.(Pilot \times Treatment)_{it}.EcoShift_i + \varepsilon_{it} \quad (8)$$

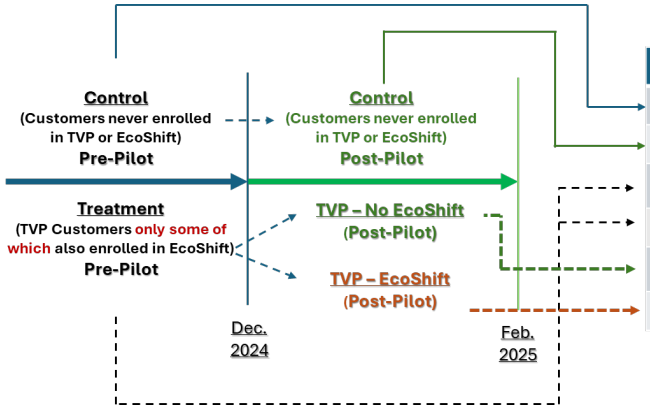
Where:

β_6 is the additional impact due to Eco Shift for TVP customers enrolled in Eco Shift program

u_i is the random intercept.

Figure 49 illustrates the diagram for binary variable matrix corresponding to the pilot groups for the Eco Shift TVP analysis. It should be noted that Eco Shift is focused on residential customers for this Phase of the TVP evaluation.

Figure 49: Eco Shift Visualization of Binary Variables



Dummy Variable Table

PilotPeriod	Treatment	EcoShift	PP x T x Eco
0	0	0	0
1	0	0	0
0	1	0 (Pre-TVP not participated in Eco)	0
0	1	1 (Pre-TVP participated in Eco)	0
1	1	0 (Post-TVP not participated in Eco)	0
1	1	1 (Post-TVP participated in Eco)	1

PP: PilotPeriod
T: Treatment
Eco: EcoShift

III.3.1.2 Economic Impact Regression Model

The regression model used for billing impact is as follows in equation (9).

$$DailyBill_{it} = \beta_0 + \beta_1.Treatment_i + \beta_2.PilotPeriod_t + \beta_3.(Pilot \times Treatment)_{it} + \beta_4.HDD_{it} + \beta_5.(Pilot \times Treatment)_{it}.HDD_{it} + \varepsilon_{it} \quad (9)$$

Where:

DailyBill$_{it}$ is the average Daily Bill in $ per day by customer '*i*' for the time period of '*t*'.

β_0 is the intercept reflecting the average Daily Bill which is independent of any independent variables).

β_1 is the coefficient describing the correlation between being a treatment customer and the average daily bill.

β_2 is the coefficient describing the correlation between being during the pilot period and the average daily bill.

β_3 is the coefficient describing the correlation between being a treatment customer during pilot period and the daily bill.

β_4 is the coefficient describing the correlation between *HDD* and the average daily bill.

β_5 is the coefficient describing the correlation between *Pilot*×*Treatment*, *HDD* and the daily bill.

β_4+β_5×HDD represents the effect of TVP on the average daily bill.

The regression models for daily price elasticity and inter-period substitution price elasticity are presented in equations (10) and (11), respectively.

$$\begin{aligned} ln(Daily\ Avg\ Usage\ kWh)_{it} = \\ &= \beta_0 + \beta_1.Treatment_i + \beta_2.PilotPeriod_t \\ &+ \beta_3.(Pilot \times Treatment)_{it} + \beta_4.ln(Temp_K)_{it} \\ &+ \beta_5.(Pilot \times Treatment)_{it}.ln(Temp_K)_{it} \\ &+ \beta_6.\ln\left(Avg\ Energy\ Price\frac{\$}{kWh}\right) \\ &+ \beta_7.\left(Avg\ Energy\ Price\frac{\$}{kWh}\right).ln(Temp_K)_{it} + \varepsilon_{it} \end{aligned} \quad (10)$$

Where:

ln(Daily Avg Usage kWh) is the natural logarithm of daily average electricity usage in kWh.

β_0 is the intercept.

ln(Temp_K) is the natural logarithm of Temperature in Kelvin.

β_4 is the coefficient reflecting the effect of natural logarithm of temperature on daily average usage.

β_5 reflects the effect of natural logarithm of temperature on TVP impact on daily average usage.

β_6 is the coefficient describing the correlation between natural logarithm of daily usage and the natural logarithm of average energy price, reflecting the customers' price responsivity.

β_7 reflects the effect of natural logarithm of temperature on customers' price responsivity.

$\beta_6+\beta_7\times ln(Temp_K)$ represents the daily price elasticity.

$$\ln\left(\frac{AvgPeak\ Load\ kW}{Avg\ OffPeak\ Load\ kW}\right)_{it} = \\ = \beta_0 + \beta_1.Treatment_i + \beta_2.PilotPeriod_t \\ + \beta_3.(Pilot \times Treatment)_{it} + \beta_4.\Delta Temp_{it} \\ + \beta_5.(Pilot \times Treatment)_{it}.\Delta Temp_{it} \\ + \beta_6.\ln\left(\frac{Peak\ Energy\ Price}{OffPeak\ Energy\ Price}\right) \\ + \beta_7.\ln\left(\frac{Peak\ Energy\ Price}{OffPeak\ Energy\ Price}\right).\Delta Temp_{it} + \varepsilon_{it} \quad (9)$$

Where:

ln(Avg Peak Load kW/Avg OffPeak Load kW) is the natural logarithm of Peak to Off-Peak load ratio.

Δ(Temp) is the difference between average peak temperature and average off-peak temperature.

β_5 reflects the effect of temperature difference between peak and off-peak on TVP impact.

β_6 is the coefficient describing the correlation between logarithm of Peak to Off-Peak load ratio and the logarithm of Peak to Off-Peak Energy Price ratio.

β_7 reflects the effect of temperature difference between peak and off-peak on customers' ability to substitute less expensive with expensive electricity usage.

$\beta_6+\beta_7\times\Delta$ ***(Temp)*** results in the inter-period substitution price elasticity.

III.3.2 Commercial TOU & CPP

This section presents the methodology used to determine the load, usage, and economic impact of the commercial TOU and CPP tariffs. The estimates for load and economic impacts are rounded and reported according to the number of significant figures supported by the margin of error at the 90% confidence level to avoid implying false precision. Although some values are reported with three significant figures, most are presented with two significant figures.

Linear Mixed effect model – The evaluation of Commercial CPP and TOU impacts is based on panel data estimation approach with pre-pilot and pilot treatment data in the absence of control group using a Mixed-Effects regression analysis. Given the relatively small sample sizes for commercial TOU (n = 50) (Table 33) and commercial CPP (n = 28) (Table 42), and heterogeneity of commercial TVP participants including General and Small General businesses, a careful selection process between Fixed Effect and Mixed Effect modeling for Commercial-TVP impact evaluation was considered, where the choice of the analysis approach can affect the precision and reliability of the estimated TVP program impacts. This comparison is accounted for in Attachment V: Validation of Mixed Effects Regression where the mixed effects model is determined to be a solution to heterogeneity.

Within subject design – Due to the absence of control group, NS Power used semi-difference-in-difference (semi-DiD) method, where NS Power estimate load and economic impacts using a within-customer modeling framework that compares event days to matched reference days (CPP) and pilot to pre-pilot (TOU).

Analysis by Cohort – Opposite to the residential load impact evaluation, an analysis by cohort is not feasible for commercial due to low sample sizes introducing statistical insignificance.

Weather Adjusted – To ensure that premise-specific load patterns are not primarily driven by HDD, NS Power applied a weather-adjustment refinement to hourly load data for each premise based on the marginal effect of HDD on electricity load using the regression model in equation (11).

$$L_{i,t} = \alpha + \beta_i . HDD_t + \varepsilon_{i,t} \quad (11)$$

Where:

$\boldsymbol{L_{i,t}}$ is the hourly consumption (kW) for premise 'i' at time 't'.

$\boldsymbol{\alpha}$ is the regression intercept.

$\boldsymbol{\beta_i}$ is the unique premise identifier.

$\boldsymbol{HDD_t}$ are the heating degree days (°C) at time 't'

$\boldsymbol{\varepsilon_{i,t}}$ is the Regression error

The adjusted load ($L_{i,t}^{adj.}$) was obtained by subtracting the estimated HDD-driven component ($\beta_i . HDD_t$) from the hourly electricity consumption ($L_{i,t}$) for each premise as shown in equation (12).

$$L_{i,t}^{adj.} = L_{i,t} - \beta_i . HDD_t \quad (12)$$

Seasonality – In addition to baseload and business type heterogeneity, seasonality of the business is a factor that affects the load shape among Commercial CPP and TOU participants, making the average consumption pattern not necessarily representative of the consumption pattern of any one of the premises. Customers on a seasonal service under Regulation 3.3 are not eligible for TOU or CPP rates and are therefore excluded. However, customers not on seasonal service may still have seasonal load profiles.

Identification of businesses with seasonal load profiles and removing them from the load data can make the data more representative, especially for analyzing the Commercial CPP and TOU load impact during Winter. NS Power conducted a premise-level seasonal analysis to identify and exclude non-Winter-oriented (seasonal) businesses from the evaluation.

A weather-adjusted hourly load (kW) was used for each premise for the seasonal analysis, where the monthly average load values were calculated for each Winter month (November–March) and each non-Winter month (April–October). Then, the Seasonal Load Ratio (SLR) was evaluated for each premise by calculating the ratio of mean Winter to non-Winter hourly consumption for each premise,

following common segmentation practice in demand research (e.g., Borenstein, 2005[23]; Hledik et al., 2010[24]); refer to equation (13).

$$SLR_i = \frac{\overline{\left(L_{i,W}^{adj.}\right)}}{\overline{L_{i,S}^{adj.}}} \quad (13)$$

Where:

$\overline{L_{i,W}^{adj.}}$ is the Winter average adjusted-load for each premise.

$\overline{L_{i,S}^{adj.}}$ is the non-Winter averaged adjusted-load for each premise.

A seasonal load ratio (SLR) threshold of 0.7 was used to indicate substantially lower electricity usage (>30% drop in electricity usage) during the Winter period. A premise was classified as seasonal if at least two Winter months exhibited SLR smaller than the SLR threshold of 0.7, indicating an average electricity usage reduction of >30% during the Winter period compared to the mean load during the non-Winter period.

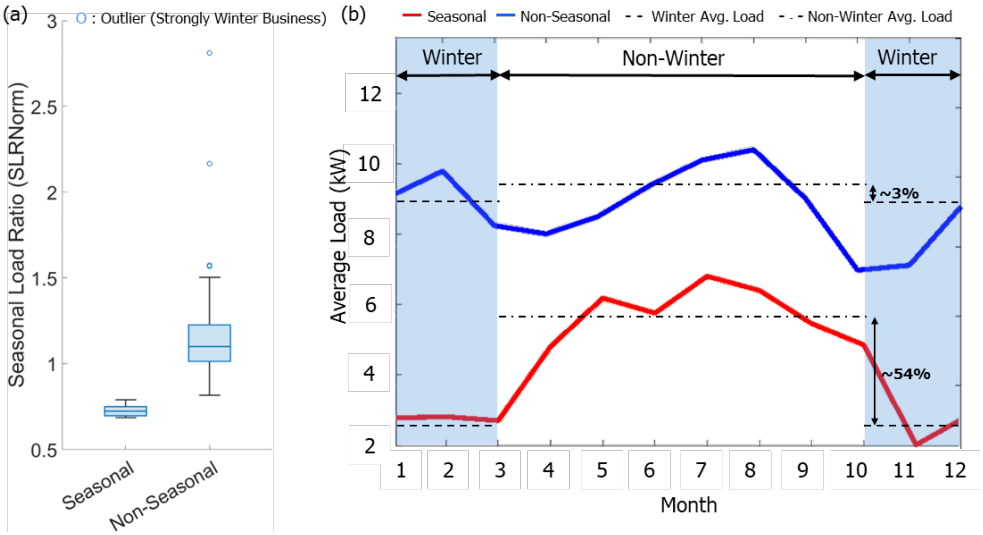
Figure 50a presents the results of the seasonality segmentation for all cohorts of TVP commercial participants based on the SLR. As shown in Figure 50a, most businesses are classified as non-seasonal, with a median SLR value greater than 1.1, while five businesses are identified as seasonal, exhibiting a median SLR value below 0.6. The outliers with relatively large SLR values within the non-seasonal segment correspond to strongly Winter-oriented businesses; these premises were included in the non-seasonal category and included in the evaluation of commercial TVP impacts.

Figure 50b presents monthly load patterns of seasonal and non-seasonal commercial participants during Winter and non-Winter seasons. Seasonal businesses show an approximately 54% increase in average load (kW) during non-Winter relative to Winter. In contrast, non-seasonal businesses exhibit approximately 3% change in average load across seasons.

[23] Borenstein S., The Long-Run Efficiency of Real-Time Retail Electricity Pricing, 2005.

[24] Hledik, R., Faruqui, A., & Sergici, S., Assessing the Impact of Dynamic Pricing in Northern California, Electricity Journal, 2010.

Figure 50: (a) Seasonality Segmentation of All Cohorts of TVP Commercial Participants Based on the Seasonal Load Ratio (SLR), Distinguishing Seasonal and Non-Seasonal Businesses; and (b) Monthly Load Patterns of Seasonal and Non-Seasonal Commercial Participants during Winter and Non-Winter Seasons



III.3.2.1 Load and Usage Impact Regression Model

Considering the methodological choices discussed above, the commercial TOU and CPP load/usage, billing as well as daily and substitution price elasticity are described by the equations (14), (15), (16), and (17) respectively.

$$Load_{it} = (\beta_0 + u_i) + \beta_1.Treatment_i + \beta_2.PilotPeriod_t + \beta_3.(Pilot \times Treatment)_{it} + \beta_4.HDD_{it} + \beta_5.(Pilot \times Treatment)_{it}.HDD_{it} + \varepsilon_{it} \quad (14)$$

Where:

***β₀** is the baseline,* ***u**ᵢ* is the random intercept reflecting the deviation from the baseload for premise *i*.

For the description of the other variables, refer to the descriptions for equation (7). For daily electricity usage impact analysis, ***Load***$_{it}$ in equation (14) is replaced by ***Energy***$_{it}$ which is the energy consumption in **kWh/day** by customer '*i*' at time '*t*'.

III.3.2.2 Economic Impact Regression Model

$$DailyBill_{it} = (\beta_0 + u_i) + \beta_1.Treatment_i + \beta_2.PilotPeriod_t + \beta_3.(Pilot \times Treatment)_{it} + \beta_4.HDD_{it} + \beta_5.(Pilot \times Treatment)_{it}.HDD_{it} + \varepsilon_{it} \quad (15)$$

$$
\begin{aligned}
ln(Daily\ Avg\ Usage\ kWh)_{it} = \\
&= (\beta_0 + u_i) + \beta_1.Treatment_i + \beta_2.PilotPeriod_t \\
&+ \beta_3.(Pilot \times Treatment)_{it} + \beta_4.ln(Temp_K)_{it} \\
&+ \beta_5.(Pilot \times Treatment)_{it}.ln(Temp_K)_{it} \\
&+ \beta_6.\ln\left(Avg\ Energy\ Price\frac{\$}{kWh}\right) \\
&+ \beta_7.\left(Avg\ Energy\ Price\frac{\$}{kWh}\right).ln(Temp_K)_{it} + \varepsilon_{it}
\end{aligned}
\tag{16}
$$

$$
\begin{aligned}
ln\left(\frac{AvgPeak\ Load\ kW}{Avg\ OffPeak\ Load\ kW}\right)_{it} = \\
&= (\beta_0 + u_i) + \beta_1.Treatment_i + \beta_2.PilotPeriod_t \\
&+ \beta_3.(Pilot \times Treatment)_{it} + \beta_4.\Delta Temp_{it} \\
&+ \beta_5.(Pilot \times Treatment)_{it}.\Delta Temp_{it} \\
&+ \beta_6.\ln\left(\frac{Peak\ Energy\ Price}{OffPeak\ Energy\ Price}\right) \\
&+ \beta_7.\ln\left(\frac{Peak\ Energy\ Price}{OffPeak\ Energy\ Price}\right).\Delta Temp_{it} + \varepsilon_{it}
\end{aligned}
\tag{17}
$$

Where: the coefficients and variables are as described earlier in equations.

Due to the absence of control groups for commercial TVP, the variable '*Treatment*' is excluded from equations (14), (15), (16) and (17) for load and economic impact analysis of commercial TOU and CPP, however, it is included in the MURB TOU regression.

III.3.3 MURB TOU

The evaluation of MURB TOU is based on panel data estimation approach with matched control groups and pre-pilot data using the difference-in-difference (DiD) approach similar to the residential tariffs. Given the relatively small sample size (n = 10) for MURBs, the choice of the modeling approach can affect the precision and reliability of the estimated program impacts, as such a review of the effect of choosing Fixed or Mixed effects was conducted (Attachment V: Validation of Mixed Effects Regression). Upon analysis, the MURB TOU load and billing impact regression will use a mixed-effects approach.

III.3.3.1 Load and Usage Impact Regression Model

The same regression as equation (14) was used for load impact and usage impact analyses for MURB TOU.

III.3.3.2 Economic Impact Regression Model

The same regression as equations (15), (16) and (17) was used for bill saving and price elasticity analysis for MURB TOU.

Attachment III: Methodology

In addition to the metrics calculated for commercial TOU and CPP, the effect on demand was evaluated. This analysis estimates demand using 15-minute average calculated every 15 minutes (i.e. AMI interval data), whereas actual billing demand is the 15-minute average calculated every 5 minutes. As such demand used in the evaluation is an estimate of billed demand, however, does serve as reasonable proxy for determining demand effect for the purposes of TVP EM&V.

Attachment IV: Historical Methodological Changes

All methodological modifications were made through collaboration with stakeholders and/or consultants. These changes and their progression have been summarized with two purposes.

1. Informing readers of the caveats with comparing results between different evaluation reports (i.e. Phases) can be subject to bias due to changes in methodology.
2. These methodological changes represent, in part, the progress in rate innovation and evaluation methodology developed throughout the TVP pilot program. This progress should be documented to capture the value this program has provided to itself and so that future pilot programs can benefit from this as a guide.

IV.1 Control Group Selection

Control group selection methodology is documented by the Phase, for example (Phases 1,2,3) indicates a methodology that was used in Phases 1, 2 and 3 that is no longer applicable to Phase 4 onwards unless otherwise noted.

IV.1.1 CPP (Phase 1)

Consistent with the approved evaluation plan, the CPP evaluations used a within-subject control group methodology. In practice this meant that there was no control group for CPP customers, rather the only control was treatment customers during the respective CPP reference day. After the first year of the evaluation, it was recommended by Econoler to modify the approach and create a control group for CPP customers; thus, creating consistency between CPP and TOU evaluations.

IV.1.2 E1 Program Balancing (Phase 1)

No balancing for E1 program effects was completed. As a result, the effects associated with E1 programs were not controlled for and could influence TVP EM&V results. Subsequent evaluations (i.e. Phase 2 onwards) have all balanced control group selection for E1 participation.

IV.1.3 Neighbourhood Criteria & Load Similarity Metric Data (Phase 1, 2, 3)

In the previous TVP evaluations (i.e. Phases 1-3) control selection included 2 stages.

Stage 1

The first stage determined the potential control candidate group using three increasing sizes of selection pools with pre-pilot billing data. The primary neighbourhood criteria, street name (i.e. the smallest pool) was used first. Treatment and control candidate customer billing data is linearized into monthly consumption and compared using similarity metric ‘SM’, a two-dimensional Euclidean distance calculation as defined by equation (18).

$$SM_{Monthly} = \frac{\sum_{i=1}^{12} \frac{|TM_i - CM_i|}{TM_i}}{n} \quad (18)$$

Where:

$\boldsymbol{TM_i}$ is the linearized monthly consumption for the treatment customer for month 'i'

$\boldsymbol{CM_i}$ is the linearized monthly consumption for the control customer for month 'i'

$\boldsymbol{n}$ is the number of months compared between treatment and control, n = 12 in this method.

To be considered a potential control, the similarity metric between treatment and potential control must be equal to or less than 0.2. The similarity metric was calculated using the mean absolute difference of all 12 months of linearized billing data. If 25 or more matches have been identified, the lowest 25 similarity metrics are chosen the potential control group, if less than 15 potential matches have been made, the process is repeated using the secondary neighbourhood criteria selection pool (i.e. postal code). Again, if the process identifies less than 15 potential controls, the process is repeated for the third neighbourhood selection pool (i.e. feeder). At the end of the process a list of 25 potential control customers or less per treatment customer is created and used to query the NS Power internal AMI database in stage 2.

Stage 2

AMI data from the neighbourhood selection pool candidates will be aggregated to average hourly interval consumption and peak hourly interval consumption during Winter and non-Winter, weekdays and weekends, creating two sets 96 data points per customer. This aggregated AMI data is then used to calculate a new two-dimensional Euclidean distance similarity metric 'SM_{AMI}' as defined by equation (1).

The calculation is completed for each treatment customer and their respective potential control, with the ten lowest similarity metrics being used to identify the top ten control for each treatment. A top ten list is required to balance for E1 program participation performed by 3rd party consultants with access to the E1 dataset.

IV.2 Heating Classification by Phase

The heating classification methodology has changed in each Phase of the evaluation, the method used during each Phase is described below.

IV.2.1 Phase 1

Heating classification in Phase 1 was based on rate code (i.e. 02 = Non-Electric, 03 = Electric). Premises are classified as rate 02 and 03 when first registered with NS Power as a customer. These rate codes are often not re-classified when the homes primary heating source changes. With heat pump adoption alone, Nova Scotians have electrified their heating significantly thus making their rate code classification less accurate.

IV.2.2 Phase 2

To account for customers who've modified their heating source from their original rate code classification, the heating classification methodology was modified to use AMI and nearby weather station temperature data for individual premises to classify space heating types. Data was restricted

to days where the average daily temperature is below 10 °C. The more negatively correlated a customer's consumption is to temperature (i.e. consumption increases with a temperature decrease) a customer would be classified as secondary electric (-0.6<R≤-0.35) or primary electric (-0.6≤R). The model's output is simplified for the purposes of this evaluation to consider all customers as primary or secondary electric to 'electric' (i.e. R≤-0.35). Additionally, a mean consumption threshold during the top 20 consumption days of 0.5 kW or greater was required. The top 20 mean consumption metric was to avoid classifying customers with significantly low consumption during cold days regardless of correlation coefficient. Both metrics must be satisfied to be classified as electric; refer to Table 73.

Table 73: Electric Space Heating Classification Requirements

Mean load during top 20 consumption days	R≤-0.35	R>-0.35
<0.5 kW	Non-Electric	Non-Electric
≥ 0.5 kW	Electric	Non-Electric

The methodology was an improvement, however, this classification did not account for changes in heating type between pre-pilot and pilot period.

IV.2.3 Phase 3

To account for customers changing heating types between pre-pilot and pilot period, Phase 3 included a pre-pilot and pilot period evaluation of heating classification using the same methodology as in Phase 2, with the distinction of taking the difference between heating classifications to define four new heating classifications; refer to Table 74.

Table 74: Heating Classification Definition

Heating Classification	Pre-Pilot	Pilot Period
Steady Electric	Electric	Electric
Steady Non-Electric	Non-Electric	Non-Electric
Electrified	Non-Electric	Electric
De-Electrified	Electric	Non-Electric

IV.2.4 Phase 4

Phase 4 (this Phase) of the evaluation uses a similar methodology as Phase 3, with two key distinctions that improved the accuracy of the model.

1. Heating classification is used in addition to the neighborhood criteria during control group selection. Therefore, like neighborhood criteria, a control customer must have the same heating classification as their corresponding treatment customer. By controlling for heating classification, load impact by space heating type is more accurate.
2. Instead of using AMI data from all 24 hours, data for heating classification is restricted to only overnight hours (i.e. 10 PM – 5 AM). This method will ensure that a customer who reduced their space heating load during peak hours, while maintaining electric space heating during off-peak hours will continue to be classified as electrically heated. This distinction is critical in capturing the effect of the TVP price signal on those who have modified their use of space heating due to the price signal.

IV.3 Regression Model

Changes to the regression model are documented within this section with the intent to summarize the change and its justification so that future evaluations can benefit from the iterative development of the TVP evaluation.

IV.3.1 Temperature

Temperature influences customer consumption, as such the regression model used in the first Phase of the evaluation was modified to include heating degree days, refer to equations (19) and (20) taken directly from the Phase 1 and Phase 2 evaluation reports. Note that these regression models have different coefficient nomenclature than those of the Phase 4 evaluation, however the methodology remains consistent between Phase 2, 3 and 4.

Phase 1

$$Load_{i,t} = \alpha + \pi \cdot PilotPeriod_t + \gamma \cdot Treatment_i + \beta \cdot Pilot\&Treament_{it} \quad (19)$$

Phases 2, 3 and 4

$$Load_{i,t} = \alpha + \pi \cdot PilotPeriod_t + \gamma \cdot Treatment_i + \beta \cdot Pilot\&Treament_{it} + \mu \cdot PilotTreatment_{it} \cdot HDD_{it} \quad (20)$$

Where:

$\boldsymbol{Load_{i,t}}$ is the average load in kW by customer i for each peak period of 4 hours t.

$\boldsymbol{\alpha}$ is the intercept (the average demand that is independent of any of the independent variables).

$\boldsymbol{\pi}$ is the model coefficient describing the correlation between the pilot period and the average load.

$\boldsymbol{\gamma}$ is the model coefficient describing the correlation between being a treatment customer and the average load.

$\boldsymbol{\beta}$ is the model coefficient describing the correlation between being a treatment customer during the pilot period and the average load.

μ is the model coefficient describing the correlation between the $Pilot\&Treatment$, the HDD variable, and the average load. If significant, this value is included in the effect of TVP by multiplying it by the average HDD when the variable $Pilot\&Treatment$ is 1.

$\boldsymbol{PilotPeriod_t}$ is a binary variable that equals 0 during the pre-pilot period and 1 during the pilot period.

$\boldsymbol{Treatment_i}$ is a binary variable that equals 0 for control group customers and 1 for participant group customers.

$\boldsymbol{Pilot\&Treament_{it}}$ is a binary variable that equals 1 for participant group customers during the pilot period and 0 for all other cases.

$\boldsymbol{HDD_{it}}$ – Variable linked to the heating degree-day (with a balance temperature of 12 °C) value for peak period t and the weather station associated to participant i. This variable is generally the average HDD per day minus a fixed value determined by the regression.

IV.3.2 Commercial

The Commercial regression model used for Phases 1, 2, and 3 followed the same fixed effects regression framework as the Residential model, less the control participants due to poor control group match results.

In practice, the fixed effects specification was not successful in the commercial segment due to substantial heterogeneity within the commercial rate class. Differences in customer size, operating profiles, and load variability introduced instability and limited the model's ability to reliably capture treatment effects. As a result, the commercial model required additional consideration beyond the residential approach to better account for structural differences across customers and improve the robustness of the estimated impact. The two modifications include altering the regression from a fixed to mixed effects regression as well as introducing a robust standard error calibration, all of which is captured separately in Attachment V: Validation of Mixed Effects Regression.

Attachment V: Validation of Mixed Effects Regression

The NS Power commercial TVP evaluations (Phase 1 – 3)[25] has historically provided statistically insignificant results. Findings such as "statistically insignificant" can be simplified to two meanings:

1. You do not reject the null hypothesis, hence there is no effect from TVP.
2. Due to sample size and or methodological choices the power of the analysis is low, resulting in Type II error (i.e. false negative).

Sample sizes have steadily increased each Phase for TVP, which is helpful in reducing Type II error, however, sample size is not a parameter that can be increased further by this evaluation. Methodology, however, has remained relatively consistent each year and should be re-examined. Using the residential model for the commercial rate classes, perhaps for consistency seems ideal, however in practice it introduced a flaw into the analysis. One important distinction between the two rate classes (residential & commercial) is how homogeneous residential customer load profiles are compared to the heterogenous commercial customer load. Although this is not an arduous claim, evidence to support such a claim is found in the control group selection methodology continuously failing to find an adequate 1:1 match for commercial customers (refer to section 0

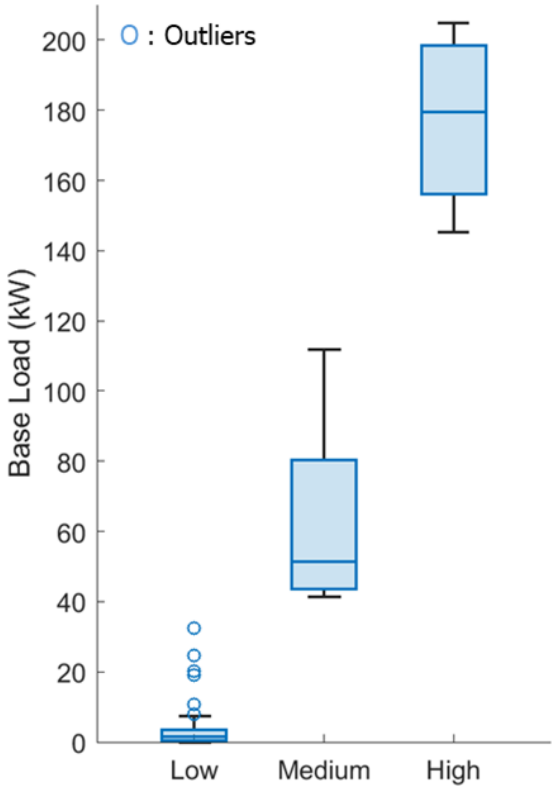
[25] NS Power, TVP EM&V Reports Phases 1 – 3 , NSEB Matter Numbers (M10703, M11267, M11823)

Control Group Selection) relative to residential customers. As such, the methodological choice to use a fixed effects regression model for commercial customers, like residential, would undoubtedly introduce significant Type II error. In the Phase 4 evaluation, the regression model was redesigned to include mixed effects, ultimately controlling for the heterogenous nature of commercial baseloads and load. Validation of this choice is provided for both the original commercial TOU and CPP rates and the new MURB TOU rate in the subsequent sections.

Commercial TOU and CPP Customers

Figure 51 illustrates the baseload heterogeneity of TVP commercial premises, where substantial differences in baseline (Low, Medium and High), associated with time-invariant variables (e.g. size of the business), can be distinguished across TVP commercial participants. Regarding this baseload heterogeneity across commercial customers, it is important to mention that a Fixed-Effect model absorbs the time-invariant differences by eliminating the heterogeneity from the analysis and assigning it to the error[26]. In contrast, a Mixed-Effect model accounts for the time-invariant differences, such as the baseload heterogeneity (Figure 51), among commercials by capturing them in the random intercept instead of error term.

Figure 51: The Baseload Heterogeneity, Classified as Low, Medium and High, across Commercial TVP Participants



[26] Frees, E. W. (2003). Longitudinal and Panel Data: Analysis and Applications for the Social Sciences. Cambridge University Press.

For commercial TOU customers during Phase 4, Figure 52(a,b) present a comparison between Fixed-Effect and Mixed-Effect based analysis. For commercial TOU customers, the Fixed-Effect model produces substantially higher residual autocorrelation than the Mixed-Effect model (Figure 52a), indicating weaker control for time-series dependence in the load data. Likewise, the Fixed-Effect model yields a noticeably larger median residual error relative to the Mixed-Effect model (Figure 52b). Examination of the residual error distributions further highlights these differences, where the Fixed-Effect model exhibits a negatively skewed distribution with a much larger median residual error (Figure 52c) than the Mixed-Effect model that produces an approximately normal and well-centered distribution with a median residual error of near zero (Figure 52d).

Figure 52: (a) A Comparison of Residual Autocorrelation and (b) Median of Residual Error between Fixed Effect and Mixed Effect Modelling Approaches for Commercial-TOU Customers Evaluated for Load Reduction, along with the Residual Error Distribution Associated with (c) Fixed Effect Modelling and (d) Mixed-Effect Modelling

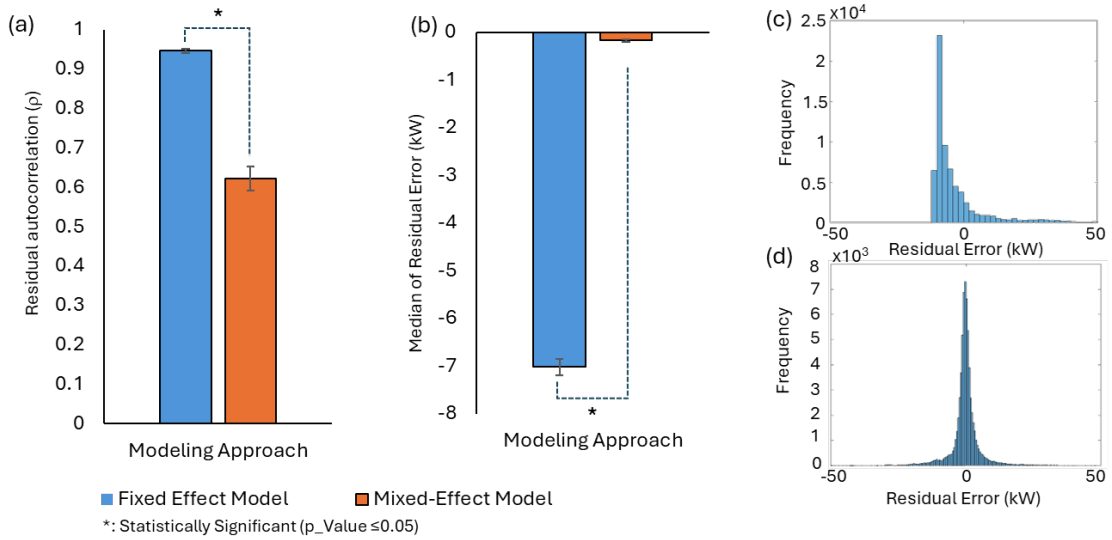
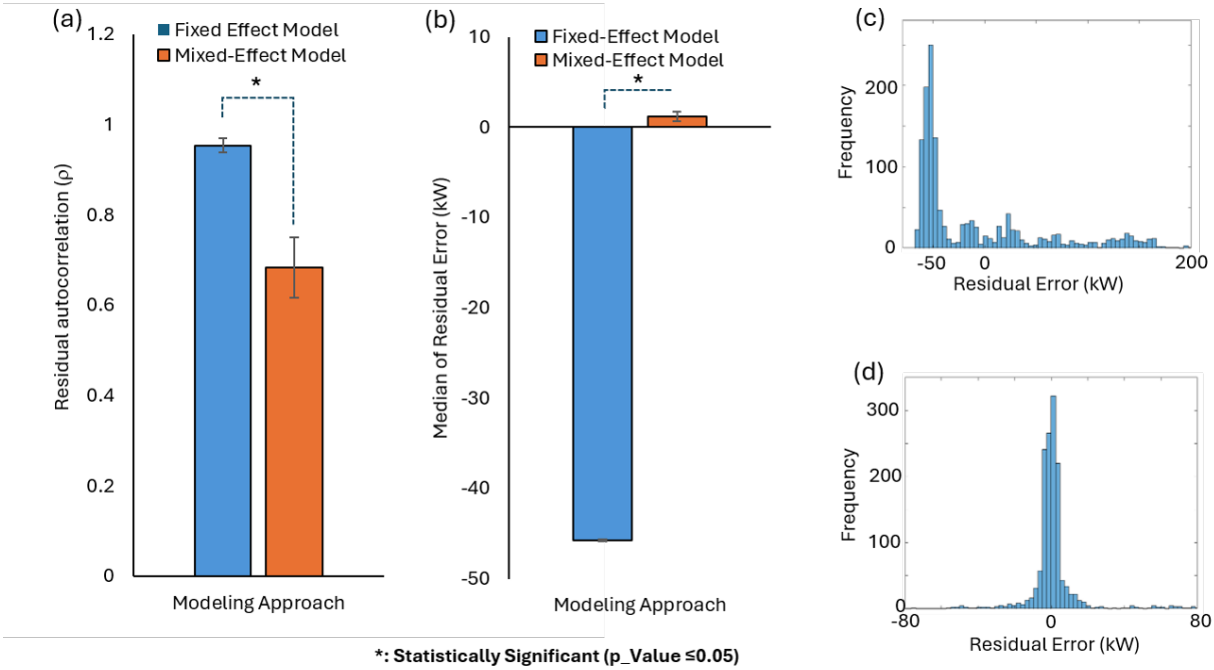


Figure 53(a,b) compare residual autocorrelation (ρ) and the median residual error (RE) between Fixed-Effect and Mixed-Effect modeling approaches used to evaluate load reduction by commercial CPP participants during CPP events in Phase 4. The Mixed-Effect model exhibits substantially lower residual autocorrelation (Figure 53a), indicating the suitability of Mixed Effect modeling to account for serial (time-series) variability in the Commercial-CPP load data. In addition, the Mixed-Effect model results in a significantly smaller median residual error of ~2.5 kW of load reduction compared to the Fixed-Effect model, which exhibits a median residual error of ~−45 kW, corresponding to a load increase (Figure 53b). Furthermore, the Fixed-Effect model exhibits a negatively skewed distribution (Figure 53c), while the Mixed Effect model shows an approximately normal and well-centered distribution with a median residual error of near zero (Figure 53c).

Figure 53: (a) A Comparison of Residual Autocorrelation and (b) Median of Residual Error between Fixed Effect and Mixed Effect Modelling Approaches for Commercial-CPP Customers Evaluated for Load Reduction during CPP Events, along with the Residual Error Distribution Associated with (c) Fixed Effect Modelling and (d) Mixed-Effect Modelling



*: Statistically Significant (p_Value ≤0.05)

Given the baseload heterogeneity, time-series (hourly) load data and the business type variability that leads to heterogeneous response patterns across commercial customers, these results suggest that the Mixed-Effect model provides a more balanced error structure and improved model fit for commercial TOU and CPP load response analysis. Thus, a Mixed-Effect model was used as this is a more statistically appropriate approach for assessing Commercial CPP and TOU impacts.

MURB TOU Customers

Unlike the commercial TOU and CPP rates, MURB TOU has not yet been evaluated using the fixed effects regression model. As such additional analyses are provided within in order to validate the choice of a mixed effects regression model (with control group) for the MURB TOU Tariff.

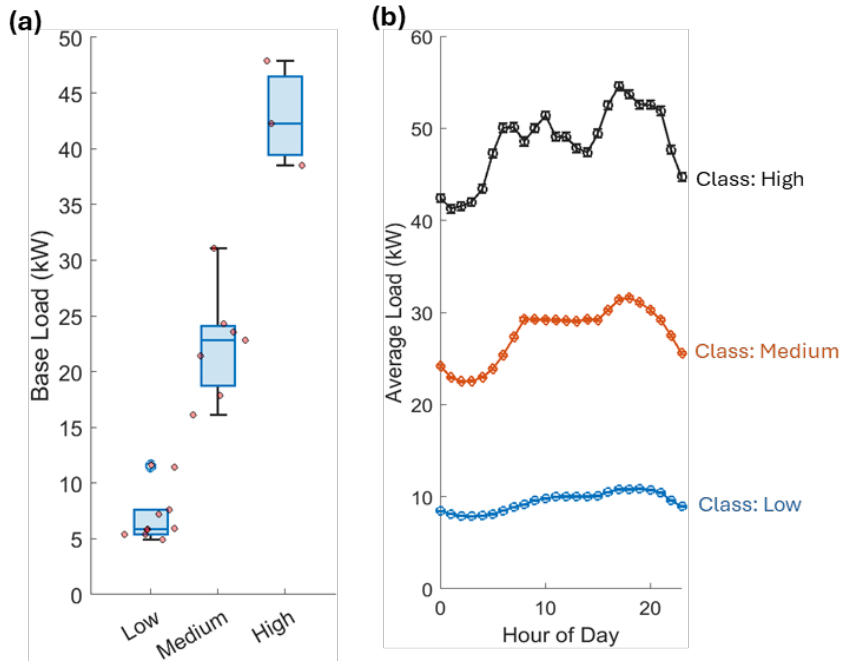
Baseload Heterogeneity Analysis

The baseline segmentation analysis indicates substantial heterogeneity in electricity consumption patterns across participating MURBs, particularly with respect to Baseload levels. Based on these characteristics, MURBs can be classified into three distinct baseline consumption classes, Low, Medium, and High, each exhibiting statistically meaningful differences in Baseline electricity consumption.

Figure 54a illustrates the distribution of baseload (kW) across the three classes. As shown in Figure 54a, baseload levels range from 5 to 8 kW for the *Low* class, 12 to 31 kW for the *Medium* class, and 38 to 47 kW for the *High* class. Furthermore, Figure 54b shows profound differences in load profile

between these classes. The clear separation in both baseload load profile confirms the presence of a substantial heterogeneity among MURB customers, which has important implications for accuracy of program impact estimation and model specification.

Figure 54: MURB TOU Classified into Three Classes (Low, Medium and High) in Terms of (a) Baseload (kW) and (b) Load Profile, Indicating Substantial Heterogeneity among MURB Customers



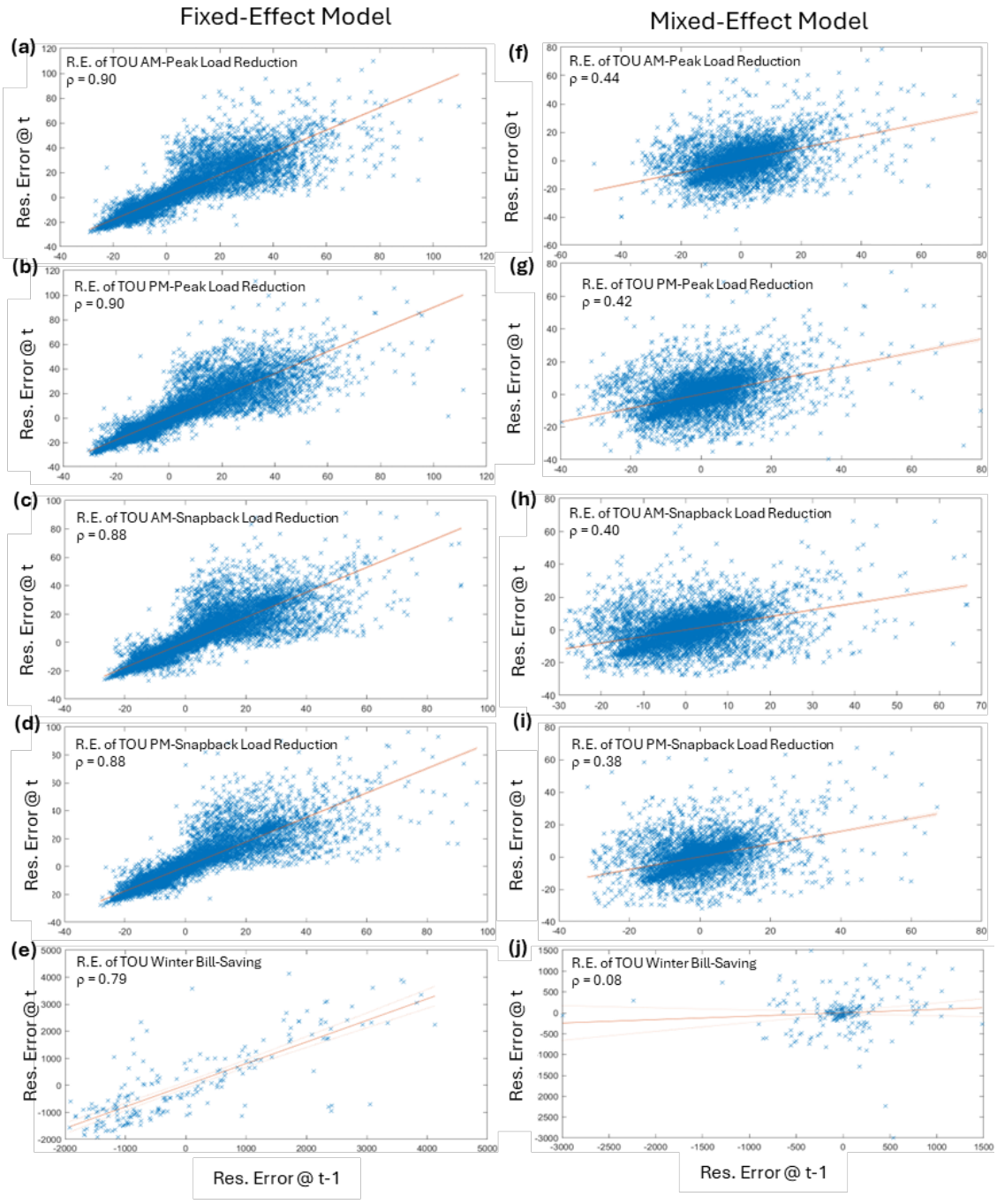
Residual Diagnostics for Fixed- vs. Mixed-Effect Modeling Approaches

It is important to note that a Fixed-Effect model absorbs the time-invariant differences, such as Baseload heterogeneity across MURBs, by eliminating it from the analysis and assigning it to the error[27]. Thus, under a Fixed-Effect Model, TOU impact estimates rely exclusively on within-premise variation over time, with baseline heterogeneity effectively removed. In contrast, a Mixed-Effect model accounts for the Baseload heterogeneity among MURBs by capturing them in the random intercept instead of error term.

Considering the substantial differences in baseline load across MURBs (Figure 54), a Mixed-Effects modeling approach appears more suitable for estimating treatment impacts under the TOU-MURB program. To assess the relative performance of the models, residual diagnostics were conducted for both Fixed-Effects and Mixed-Effects models, with a focus on comparing residual error (RE) autocorrelation (ρ) between the two approaches (Figure 55).

[27] Frees, E. W. (2003). Longitudinal and Panel Data: Analysis and Applications for the Social Sciences. Cambridge University Press.

Figure 55: The Residual Error (RE) Autocorrelation (r) Resulted from the Fixed-Effect Model (a–e) and the Mixed-Effect Model (f–j) for Evaluating (a, f) AM-Peak Load Reduction, (b, g) PM-Peak Load Reduction, (c, h) AM-Snapback Effect, (d, i) PM-Snapback Effect, and (e, j) Bill-Saving during Winter for TOU-MURBs

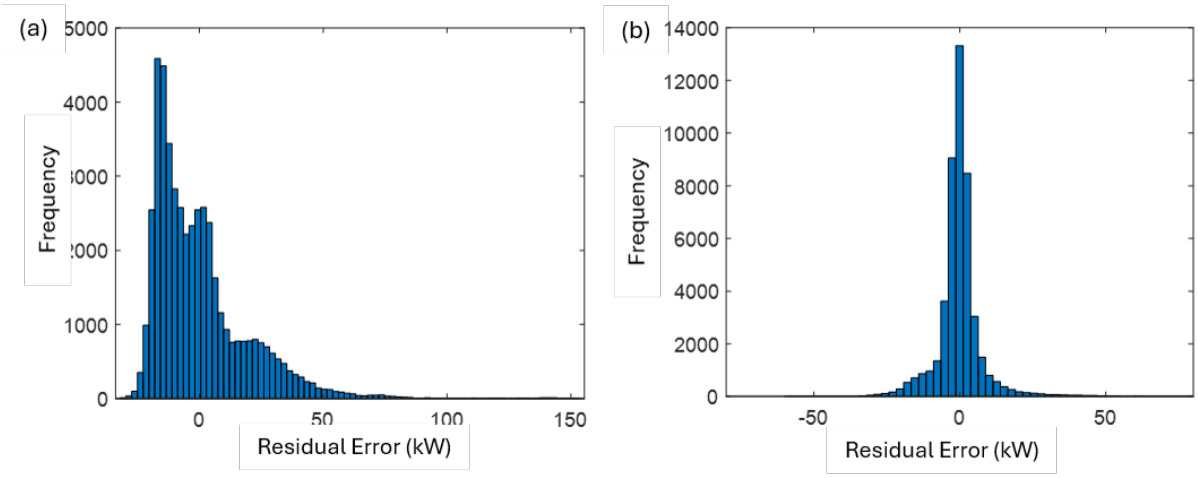


The RE autocorrelation (r) was evaluated based on the residual serial correlation between RE at time (*t*) and the RE at the previous time (*t-1*). Figure 55 presents the estimated residual serial correlation for the Fixed-Effect model (Figure 55a – e) and Mixed-Effect model (Figure 55f – j), where the models

were applied for estimating the Load-Reduction and Bill-Saving during peak and snapback hours, and during Winter, respectively. Figure 55 indicates that the magnitude of residual errors produced by the Fixed-Effects models (Figure 55a – e) is consistently larger than that observed for the corresponding Mixed-Effect models (Figure 55f – j).

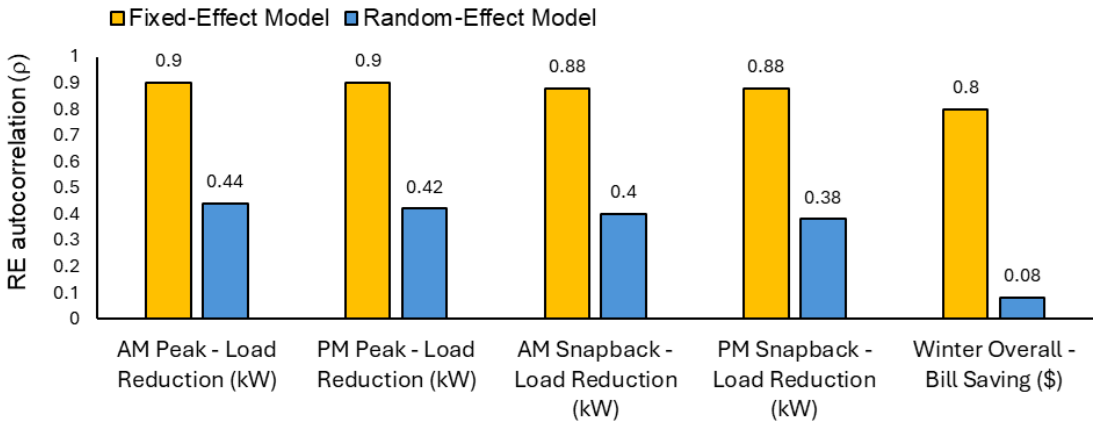
Furthermore, the Fixed-Effect model exhibits a negatively skewed distribution (Figure 56a), while the Mixed Effect model shows an approximately normal and well-centered distribution with a median residual error of near zero (Figure 56b).

Figure 56: Residual Error Distribution Associated with (a) Fixed Effect Modeling and (b) Mixed-Effect Modeling



In addition, the Mixed-Effect model exhibits substantially lower RE autocorrelation (ρ) relative to the Fixed-Effects model, as illustrated in Figure 57. This comparison implies that the influence of the Baseload heterogeneity among MURBs leaks into residuals and becomes serially correlated when the Baseload heterogeneity is excluded by the Fixed-Effect model. In contrast, the Mixed-Effect model captures the Baseload heterogeneity into random intercepts, resulting in decreased RE autocorrelation.

Figure 57: A Comparison of the Residual Autocorrelation between Fixed-Effect Model and Mixed-Effect Model for TOU-MURBs evaluated for the Load Reduction during Morning Peak (AM-Peak) hours, Evening Peak (PM-Peak) hours, Morning Snapback (AM-Snapback) and Evening-Snapback (PM-Snapback) hours, as well as for the Bill Saving ($) during Winter



Given the small sample size of MURBs (n = 10), the substantial heterogeneity in Baseline electricity consumption across MURBs (Figure 54), and the supporting results from the comparison of Fixed-Effect and Mixed-Effect models (Figure 55 & Figure 57), the Mixed-Effect modeling approach is the preferred model for estimating the impact of TOU-MURBs pilot program.

Robust Margin of Error

When TVP load impact was estimated using the DiD analysis, the residual errors can be autocorrelated. If residual autocorrelation is not adjusted for, the standard error will be underestimated. As such, it is necessary to adjust the 90% MoE as follows:

$$MoE\ (90\%)_{adj} = z.\frac{SE}{\sqrt{1-\rho^2}} \tag{21}$$

Where MoE $(90\%)_{adj}$ is adjusted MoE at 90% confidence level, z value is the critical value derived from the standard normal distribution (z-distribution) and is approximately 1.645, *SE* is the standard error, and ρ is the first-order residual autocorrelation coefficient which is calculated as follows:

$$\rho = \frac{\sum_{t=2}^{n}(e_t - \bar{e}\,)(e_{t-1} - \bar{e}\,)}{\sum_{t=1}^{n}(e_t - \bar{e}\,)^2} \tag{22}$$

Where *e* is the residual error, *t* is time, $\bar{e}$ is the mean of residual errors, and *n* is the number of data points.

Furthermore, the variance of residual errors may change across the time-load data, instead of being spread out. This results in heteroskedasticity in model predictions, which is addressed through calculating robust MoE (90%) as follows:

$$MoE(90\%)_{robust} = z.\frac{SE_{robust}}{\sqrt{1-\rho^2}} \tag{23}$$

Where SE_{robust} is the robust standard error and is obtained as:

$$SE_{robust} = \sqrt{c^T.V_{robust}.c} \tag{24}$$

Where *c* is the coefficient vector corresponding to the estimates in the model, c^T is the transpose of coefficient vector, and V_{robust} is the robust covariance matrix of the coefficients.

Attachment VI: Control Group Selection Non-Load Variables

Table 75: Average of Residential Control, Treatment and Nova Scotia Population Non-Load Baseline Characteristics (Median Income, Average Residents, Year Built, Living Space)

Metric	Rate	Treatment	Control	Population
Median Income[28]	CPP	$ 88,813	$ 85,986	$ 85,143
	TOU	$ 88,496	$ 86,853	
Average Residents per Household[28]	CPP	2.372	2.344	2.384
	TOU	2.371	2.355	
Year Built[29]	CPP	1979	1978	1979
	TOU	1979	1977	
Living Space (ft^2)[29]	CPP	1,762	1,728	1,540
	TOU	1,755	1,718	
Note: This table presents the average of the median income and average of the average residents per household per postal code.				

Table 76: Residential Control, Treatment and Nova Scotia Population Non-Load Baseline Characteristics (Housing Style)

House Style[29]	Customer count by group			Percent by group		
	Treatment	Control	Population	Treatment	Control	Population
1 Storey	2,457	2,653	156,145	33.9	36.6	40.7
2 Storey	1,927	1,818	75,435	26.6	25.1	19.7
1.5 Storey	864	799	54,647	11.9	11.0	14.3
Split Entry	747	777	31,987	10.3	10.7	8.3
Manufactured Home	117	180	19,373	1.6	2.5	5.1
Unknown	0	0	12,588	0.0	0.0	3.3
2 Storey Semi Detached	368	268	9,401	5.1	3.7	2.5
Split Level	199	207	8,511	2.7	2.9	2.2
2 Storey Townhouse	236	196	3,743	3.3	2.7	1.0
1 Storey Semi Detached	95	63	3,332	1.3	0.9	0.9
1 Storey Duplex	57	65	2,212	0.8	0.9	0.6
2 Storey Duplex	65	67	1,712	0.9	0.9	0.4
2.5 Storey	32	41	1,114	0.4	0.6	0.3

[28] Median Income & Average Household Residents data, Source: Environics Analytics 2024 modelling of Statistics Canada FSA income survey results to 6-digit postal code, mapped to control and treatment using 6-digit postal code.

[29] Property Valuation Services Corporation (PVSC), mapped by nearest property using latitude and longitude radii calculation, where "House Style" is limited to non-MURB housing. Note: This does not indicate MURB participants do no exist in TVP.

Attachment VI: Control Group Selection Non-Load Variables

House Style[29]	Customer count by group			Percent by group		
	Treatment	Control	Population	Treatment	Control	Population
1.5 Storey Semi Detached	11	13	1,085	0.2	0.2	0.3
1 Storey Townhouse	26	23	750	0.4	0.3	0.2
3 Storey	16	21	365	0.2	0.3	0.1
1.5 Storey Duplex	0	3	138	0.0	0.0	0.0
Additon	0	1	132	0.0	0.0	0.0
1 Storey Triplex	6	4	120	0.1	0.1	0.0
2 Storey Triplex	7	10	113	0.1	0.1	0.0
3 Storey Townhouse	1	1	76	0.0	0.0	0.0
2.5 Storey Townhouse	7	7	61	0.1	0.1	0.0
1 Storey Quadruplex	3	8	60	0.0	0.1	0.0
1.5 Storey Townhouse	0	0	58	0.0	0.0	0.0
3 Storey Semi Detached	3	10	56	0.0	0.1	0.0
2.5 Storey Semi Detached	1	4	43	0.0	0.1	0.0
2 Storey Quadruplex	3	3	31	0.0	0.0	0.0
2.5 Storey Duplex	0	1	15	0.0	0.0	0.0
3 Storey Triplex	0	1	12	0.0	0.0	0.0
1.5 Storey Triplex	0	0	8	0.0	0.0	0.0
2.5 Storey Triplex	0	0	6	0.0	0.0	0.0
3 Storey Duplex	0	1	6	0.0	0.0	0.0
3 Storey Quadruplex	0	2	5	0.0	0.0	0.0
2.5 Storey Quadruplex	2	3	4	0.0	0.0	0.0
1.5 Storey Quadruplex	0	0	1	0.0	0.0	0.0

Attachment VII: Board Directives and Consensus Agreement Commitments

NS Power has reviewed all Nova Scotia Energy Board (NSEB) directives pertinent to the TVP Phase 4 EM&V report and has responded to, using reference to previously filed content and/or additional analyses as required.

Demand Response Overlap between NS Power and E1

In its Decision on E1's 2026 DSM Extension Application (M12249), the Board provided:

> The Board agrees that concerns about E1's demand response programs are better addressed in its consultations and upcoming application for approval of its five-year DSM Plan. That said, the Board notes that E1 should be fully prepared to address the questions raised in this proceeding about potential overlap with NS Power's Critical Peak Pricing Program and the targeting of constrained areas of the transmission and distribution system in its application. If it fails to adequately address these issues, this may complicate the approval of its DSM Plan. The Board expects NS Power to cooperate fully with E1 in exploring these issues.

To evaluate these questions of potential overlap, an evaluation was completed where a subset of participants who were enrolled in both Eco Shift and Critical Peak Pricing rates received a coordinated set of event calls from both programs and were segregated from the broader pilot to evaluate any potential incremental load shift above that which is attributable to Critical Peak Pricing alone. The analysis was further extended to participants who were enrolled in both Eco Shift and Time-of-Use rates. NS Power has provided the interactive load effects of Eco Shift and TVP (both TOU and CPP) in Sections 3.1.1, 4.1.1, 5.1.1, and 6.1.1. A discussion on the Methodology is provided in Section 2.1.1 and in Attachment III: Methodology.[30]

[30] M12249 – Board Decision, 326722, page 26, para. 65. December 22, 2025.

Coincidence of Critical Peak Events and System Margin

In its Decision and Order on the Year Three (2023/24) Evaluation Report (Year Three Report) in M11823, the Board provided:

> NS Power agreed with Synapse that system margin forecasts may be a better indicator of when to call a CPP event. The Board directs NS Power to provide an analysis of the correspondence of system margin forecasts and CPP events in the Year 4 report, providing the days with a forecast of low system margin and the forecast system margin for the days when a CPP event was called. Further, NS Power is directed to work with stakeholders to refine its methods of estimating load reductions achieved through the TVP tariffs.[31]

Upon analysis of historical forecast system margin during the Phase 4 Winter, the system margin forecast during CPP events was 91.6 percent less than during all other non-CPP event hours between 7 – 11 AM and 5 – 9 PM. The dates in which system margin was forecast to be low (≤ 50 MW), and whether this correlated with a scheduled Critical Peak Event during the 2024/25 Winter Season (i.e. Phase 4) is provided in Table 77.

Table 77: Dates and Times of Low Forecast System Margin and Whether a Critical Peak Event was Scheduled during the 2024/25 Winter Season

Period of Low Forecast System Margin		During Scheduled Critical Peak Event
Date	Hour Start	Yes / Cancelled / No
2024-12-04	17:00	Yes
2024-12-04	18:00	
2024-12-04	19:00	
2024-12-04	20:00	
2024-12-15	17:00	Yes
2024-12-15	18:00	
2024-12-15	19:00	
2024-12-15	20:00	
2024-12-20	7:00	Yes
2024-12-20	8:00	
2024-12-20	9:00	
2024-12-20	10:00	
2024-12-22	17:00	Yes
2024-12-22	18:00	
2024-12-22	19:00	
2024-12-22	20:00	
2024-12-23	7:00	Yes
2024-12-23	8:00	
2024-12-23	9:00	
2024-12-23	10:00	
2024-12-23	17:00	Yes

[31] M11823 – Board Decision and Order, 316514, page 5. October 31, 2024.

Period of Low Forecast System Margin		During Scheduled Critical Peak Event
Date	Hour Start	Yes / Cancelled / No
2024-12-23	18:00	
2024-12-23	19:00	
2024-12-23	20:00	
2025-01-21	17:00	Yes
2025-01-21	18:00	
2025-01-21	19:00	
2025-01-21	20:00	
2025-01-22	7:00	Yes
2025-01-22	8:00	
2025-01-22	9:00	
2025-01-22	10:00	
2025-02-02	17:00	Yes
2025-02-02	18:00	
2025-02-02	19:00	
2025-02-02	20:00	
2025-02-05	17:00	Yes
2025-02-05	18:00	
2025-02-05	19:00	
2025-02-05	20:00	
2025-02-06	7:00	Yes
2025-02-06	8:00	
2025-02-06	9:00	
2025-02-06	10:00	
2025-03-04	7:00	Yes
2025-03-04	8:00	
2025-03-04	9:00	
2025-03-04	10:00	
2025-03-10	7:00	Yes
2025-03-10	8:00	
2025-03-10	9:00	
2025-03-10	10:00	
2025-03-11	7:00	Yes
2025-03-11	8:00	
2025-03-11	9:00	
2025-03-11	10:00	
2024-12-10	17:00	Cancelled Event
2024-12-10	18:00	
2024-12-10	19:00	
2024-12-10	20:00	
2025-02-12	7:00	Cancelled Event
2025-02-12	8:00	
2025-02-12	9:00	

Attachment VII: Board Directives and Consensus Agreement Commitments

Period of Low Forecast System Margin		During Scheduled Critical Peak Event
Date	**Hour Start**	**Yes / Cancelled / No**
2025-02-12	10:00	
2025-02-12	17:00	Cancelled Event
2025-02-12	18:00	
2025-02-12	19:00	
2025-02-12	20:00	
2024-11-02	16:00	No
2024-11-02	17:00	
2024-11-02	18:00	
2024-11-02	19:00	
2024-11-02	20:00	
2024-11-02	21:00	
2024-11-03	16:00	No
2024-11-03	17:00	
2024-11-03	18:00	
2024-11-03	19:00	
2024-11-03	20:00	
2024-11-04	7:00	No
2024-11-04	8:00	
2024-11-04	9:00	
2024-11-04	15:00	No
2024-11-04	16:00	
2024-11-04	17:00	
2024-11-04	18:00	
2024-11-04	19:00	
2024-11-04	20:00	
2024-11-04	21:00	
2024-11-04	22:00	
2024-11-24	17:00	No
2024-11-24	18:00	
2024-11-26	7:00	No
2024-12-16	7:00	No
2024-12-23	16:00	No
2024-12-23	21:00	No
2024-12-23	22:00	
2024-12-24	7:00	No
2024-12-24	8:00	
2024-12-24	9:00	
2024-12-24	17:00	No
2024-12-24	18:00	
2025-01-13	16:00	No
2025-01-13	17:00	
2025-01-13	18:00	

Attachment VII: Board Directives and Consensus Agreement Commitments

Period of Low Forecast System Margin		During Scheduled Critical Peak Event
Date	Hour Start	Yes / Cancelled / No
2025-01-14	17:00	No
2025-01-17	6:00	No
2025-01-17	7:00	
2025-01-17	8:00	
2025-01-17	9:00	
2025-01-17	10:00	
2025-01-17	16:00	No
2025-01-17	17:00	
2025-01-17	18:00	
2025-01-18	6:00	No
2025-01-18	7:00	
2025-01-18	8:00	
2025-01-18	9:00	
2025-01-21	16:00	No
2025-01-21	21:00	No
2025-01-23	7:00	No
2025-01-29	7:00	No
2025-01-29	8:00	
2025-01-29	9:00	
2025-01-29	16:00	No
2025-01-29	17:00	
2025-01-29	18:00	
2025-01-29	19:00	
2025-01-29	20:00	
2025-02-06	5:00	No
2025-02-06	6:00	
2025-02-08	18:00	No
2025-02-09	5:00	No
2025-02-10	7:00	No
2025-02-11	7:00	No
2025-02-11	8:00	
2025-02-12	21:00	No
2025-02-13	7:00	No
2025-02-13	8:00	
2025-02-13	9:00	
2025-02-22	18:00	No
2025-02-22	19:00	
2025-02-22	20:00	
2025-03-11	6:00	No

Performance Assessment on General Service Class Customers

In its Decision and Order on the Year Three Report (M11823), the Board provided:

> The Year 3 Report notes that commercial customer enrollment in the TVP is low, making a robust evaluation of this customer group problematic. The Board directs NS Power to complete a performance assessment of the General Service Class customers, as described in Synapse's evidence, evaluating the extent that bills increase as they shift load from on-peak hours to off-peak hours. It is expected that this assessment will identify whether the demand charge increases the electricity bills for these participants. If the assessment finds that the demand charge results in higher bills to the commercial class customers shifting their load from on-peak to off-peak, NS Power is to assess removal of the demand charge, as well as any other changes, which could incentivize the participation of the commercial rate class customers in the TVP Program. The Board directs NS Power to provide the outcome of this assessment and potential tariff changes to stakeholders during an engagement session and to the Board in the Year 4 Report.
>
> The Board finds that if NS Power's assessment determines the demand charge is not a deterrent and/or the cause of lower commercial customer enrollment in the TVP, NS Power is directed to review and improve its customer engagement with commercial rate class customers and to revisit the incentive structure for the commercial TVP tariffs so that commercial operations and load shifting are not mutually exclusive.[32]

NS Power completed this analysis and presented the outcomes to TVP stakeholders at Technical Session 2, held April 7, 2025. Technical Session 2 materials are provided as Appendix E, Attachments 4 and 5 as a part of this filing.[33] In its analysis, NS Power found that approximately 44 percent of General Class customers have peak consumption that corresponds to the same peak periods identified in the General TOU Tariff. As such, shifting load away from TOU peak periods could reduce demand and further lower the customer's bill. Additionally, as outlined within the body of this Report, NS Power's evaluation has identified a statistically significant load shift in the commercial TOU rate classes (Table 34), especially in the General rate class (Figure 32b), commercial operations and load shifting are no longer mutually exclusive. This finding is the result of a key methodological improvement (i.e. random intercept / mixed effects regression) quantified in equations (14), (15), (16), and (17)and validated in Attachment V: Validation of Mixed Effects Regression.

Reporting on Small Business Characteristics that Enable Load Shifting

As part of its 2024 TVP Consensus Agreement, the Company committed to:

> h. Reporting back to stakeholders on changes that could be made to help customers determine whether they will benefit from TVP, TOU and CPP options. This report will be provided by NS Power and include the following:

[32] M11823 – Board Decision and Order, 316514, page 6.

[33] Please refer to pages 5-8 of Appendix E, Attachment 4.

i. Summary of the general load characteristics of small business customers that may enable a small business customer to shift load in response to TVP, CPP, or TOU rates.

ii. Information on commercial/small business customer recruitment tele-marketing or on-site contact with the customer (including parent company staff), as may be necessary. NS Power does not currently collect complete SIC Code data for all customers. However, NS Power agrees that this type of information would be valuable and will explore analytical opportunities that could allow customers to be classified by business sector. NS Power will provide an update on these efforts in the report.

iii. The recruitment tactics for contacting business customers for Years 4 and beyond have not yet been determined; however, should outcall be utilized, NS Power will provide the script.

iv. NS Power will provide a summary of specific reasons why customers are reluctant to participate, followed by an evaluation of the pilot tariff to see if changes can address some of the concerns, (i.e., create successful recruitment).[34]

In its Decision and Order on the Year Three Report (M11823), the Board further provided:

> NS Power agreed with Synapse's recommendation to improve customer education and to continue collecting participant feedback. As part of the 2024/25 Areas of Focus, NS Power will develop and provide stakeholders with an analysis of commercial class customer characteristics that have the capacity in the TVP to reduce load at peak periods.[35]

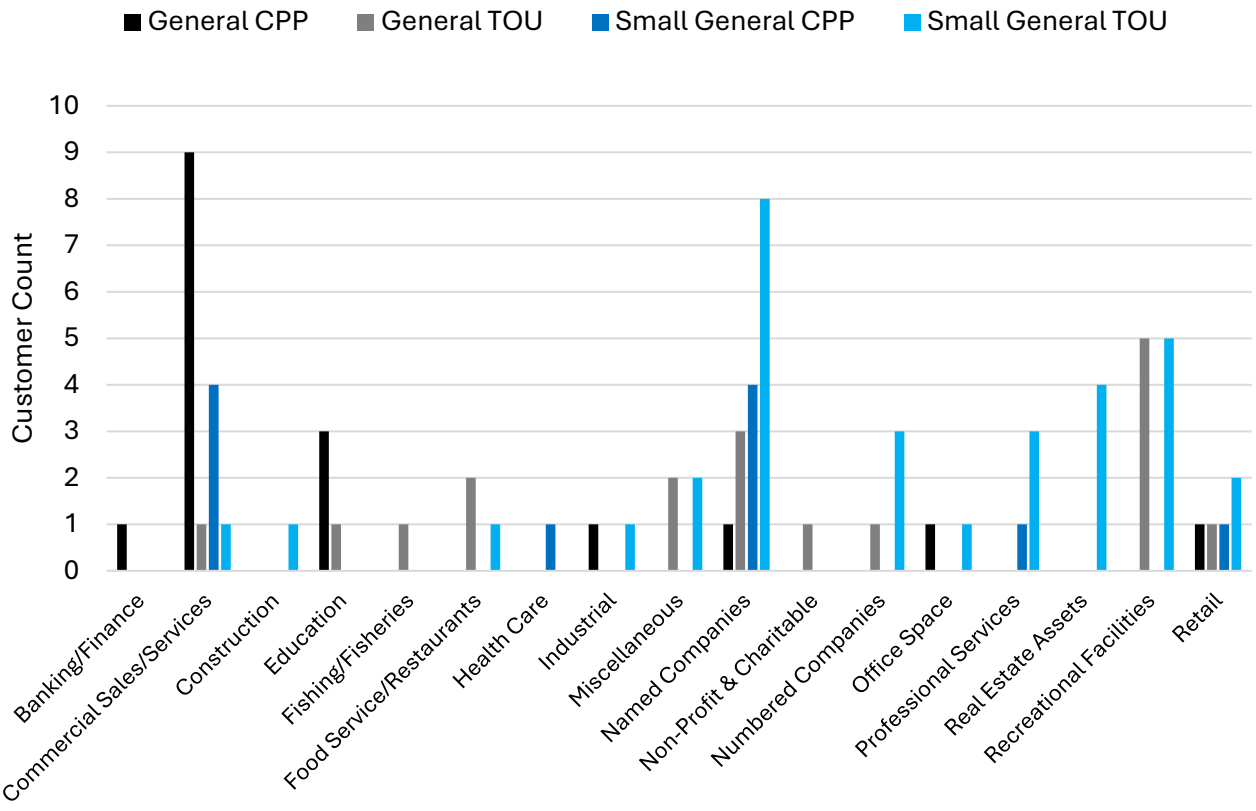
In relation to the summary of general load characteristic, load shifting (kW per customer) in both TOU and CPP commercial rates was primarily driven by the General rate class (Figure 32b & Figure 38b). This rate characteristic, which is determined by the business' scale of energy consumption, is the only characteristic found to date which impacts load shifting response. Based on the business verticals used to classify customers[36], an estimated breakdown of participating commercial customers by TVP Tariff and business vertical is provided in Figure 58.

[34] M11822 – TVP Consensus Agreement (Appendix A), pages 8-9. July 31, 2024.

[35] M11823 – Board Decision and Order, 316514, page 5.

[36] TVP Tariff Pilot –Technical Session 2, April 7, 2025, Slide 28.

Figure 58: Estimated Business Vertical Classification by TVP Tariff



Note that individual business vertical sample sizes are too small to provide statistically relevant load reduction estimates by business vertical. Additionally, the classification machine learning algorithm created by NS Power to provide such insight is still under development and provides no insight for "Named" (e.g. John Smith Industries) or "Numbered" (e.g. 1234567 Nova Scotia Limited). That said, NS Power will continue to monitor business verticals and improve its internal methods for classifying business customers and will report in more detail when TVP enrolment and classification methodologies provide sufficient sample sizes. As it stands based on this evaluations results, the General rate class, regardless of business vertical, demonstrates the current best area of focus for commercial customers (refer to Figure 32b & Figure 38b).

Further details were provided as part of Technical Session 2 (held on April 7, 2025). Technical Session 2 materials are provided as Appendix E, Attachments 4 and 5 to this Report.[37] Commercial customer marketing and recruitment materials are provided as Appendix C: Marketing and Recruitment.

[37] Please refer to Appendix E, Attachment 4, pages 18-28 and Appendix E, Attachment 5, pages 2-3.

Review of Marketing and Communication Efforts

In its Decision and Order on the Year Three Report (M11823), the Board provided:

> Narrative Research conducted a customer survey, which highlighted residential customers' dissatisfaction regarding bill savings. Synapse recommended NS Power analyze the differences in satisfaction among the tariffs and demographics and find improvements in communication with customers, particularly about bill savings. NS Power indicated that there will be a review of marketing and communication efforts with stakeholders through the pricing innovation process. The Board believes it is important that NS Power adequately communicate with the Pilot participants to set their bill savings expectations appropriately to ensure the Pilot can maintain enrollment, produce high-quality results and protect the trust of NS Power customers. NS Power is directed to report on the review of its marketing and communication efforts and its planned changes, informed by stakeholders through the pricing innovation process, in the Year 4 Report.[38]

For residential customers, NS Power equipped Customer Care agents with a purpose-built estimation tool to support inbound customer inquiries about TVP. When customers called to ask how time-varying rates might affect their bill, Customer Care representatives could generate estimated bill comparisons across available rate options (TOU & CPP) based on their energy usage profile and typical load shifting behaviour. This allowed agents to provide clear, data-driven guidance on potential savings or cost impacts, helping residential customers make informed decisions without requiring in-depth technical analysis or follow-up engagement.

NS Power engaged commercial business customers on the TVP program through a coordinated approach that combined relationship management with advanced analytics. Key Account Managers acted as the primary liaison between business customers and Nova Scotia Power, helping customers understand TVP, gathering operational context, and communicating objectives and considerations. Detailed analysis was then carried out by the data analytics team, who evaluated interval load data to model load-shifting opportunities, peak effects, and estimated bill impacts under different rate scenarios. The resulting metrics and savings estimates enabled customers to clearly assess which rate best aligned with their operational profile.

Please refer to Appendix C which provides the marketing, recruitment, and communication efforts for the 2024/25 Season. NS Power reviewed its planned marketing and recruitment efforts with TVP Stakeholders as part of Technical Session 1 (held on March 3, 2025). Technical Session 1 materials are provided as Appendix E, Attachments 3 and 4 to this Report.[39]

Other Board Directives and Consensus Agreement Commitments

Across the 2024 Consensus Agreement, Year Three Report (M11823), 2024/25 TVP Application (M11822), and other proceedings, other Board directives and commitments have been made. Throughout the 2024/25 TVP Season, the Company reviewed several of these items through NS Power's pricing innovation process and stakeholder consultative sessions. As part of the Company's October 1, 2025 Submission seeking Board approval to temporarily modify the TVP Pilot for the

[38] M11823 – Board Decision and Order, 316514, pages 5-6.

[39] Please refer to Appendix E, Attachment 3, pages 32-43 and 48-60, and Appendix E, Attachment 4, pages 38-41 and 46-47.

2025/26 Season (M12499), NS Power provided an update on the status of these directives and commitments. In its letter on NS Power's December 2025 Year Four Report extension request (M12499), the Board provided:

> The Board approves NS Power's request to extend the filing date of the TVP 2024/25 (Year Four) EM&V report to June 30, 2026, or earlier if the Company is able to do so. The Board also approves the deferral of the outstanding Board directives and Consensus Agreement commitments to future Technical Sessions or the Year Four EM&V report. However, for greater certainty, NS Power is directed to report on the status of these directives and Consensus Agreement commitments when it files its Year Four EM&V report.[40]

NS Power has provided an update on the status of these directives as Attachment 1 to the cover letter for this Report.

[40] M12499 – Board Letter, 326792, page 2. December 23, 2025.

NARRATIVE RESEARCH

Time-Varying Pricing Report 2025

May 2025

Prepared for:

Nova Scotia POWER
An Emera Company

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NARRATIVE RESEARCH

Background and Purpose

Background and Purpose

Background

- For the past few years, NSP has commissioned Narrative Research to collect feedback from participants of two rate plans: Time-of-Use and Critical Peak Pricing. The purpose of this survey was to better understand customer experiences of the pilot and to understand how, if at all, things may have shifted since the last iteration..

Purpose and Objectives

- Narrative Research is conducting the survey on behalf of Nova Scotia Power. NSP was interested in collecting feedback from participants of the program (both new and ongoing participants). Research sought to achieve the following research objectives:
  - *Measure residential customer opinions and experiences of the pilot so far (including year 1, year 2, year 3, and year 4 participants);*
  - *Identify and measure the magnitude of changes in behaviour because of the new pricing plan and test program preferences;*
  - *Determine opinions about communication from NSP, including content, frequency, and easy of reading and understanding bills;*
  - *Collect feedback and potential preferences for changes to the Time-Varying Pricing Rate Pilot; and*
  - *Track changes in opinion through comparison with previous studies.*

NARRATIVE RESEARCH

Methodology

Methodology

Mode
Online survey

Audience
NSP TVP Pilot Participants (Years 1-4)

2,103 completes
Time of Use: 1,332
Critical Peak: 771

Data Collection Dates
April 10 - 16, 2025

Response Rate
27.0% (7,801 invitations sent)

Average Completion Time
23 minutes

Sampling/Administration
NSP provided Narrative with a list of pilot participants, and each were invited to complete the survey via a unique link.

Notes
Table references presented in the report refer to the detailed banner tables.

Margin of Error
Since this is an attempted census of program participants, a margin of error is not applied.

NARRATIVE RESEARCH

Summary of Objectives and Key Findings

Three Takeaways

1

Time-Varying Pricing Rate Pilot participant satisfaction remains high.

Overall participant satisfaction across both ToU and CPP is high, with just one in ten not being satisfied. Satisfaction with the Critical Peak Pricing Pilot increased in 2025 while Time-of-Use Pilot satisfaction is stable.

2

TVP participants are increasingly struggling to understand their bills.

Participants in both pilots say they are increasingly less likely to understand how the pilot participation influences their bill or to believe that their participation positively impacts their power bill.

3

Changes to either pilot will motivate some participants to leave.

One in three ToU and one in four CPP participants indicate they would consider leaving their respective pilots should changes to the pilot occur, even if an additional incentive were to be offered (ToU saw monthly base fee increase, included weekends, or non-winter periods; CPP could call peak events year round).



Summary of Objectives and Key Findings

Objectives	Key Findings
Measure residential customer opinions and experiences of the pilot	• **Overall Satsifaction:** Two thirds of TVP participants remain satisfied (scores of 7-10) while just one in ten give low scores of 1-4. Participant satisfaction with CPP increased this year while ToU satisfaction remains stable. • **Participant Tenure:** Year 4 participants (recent joiners) report the lowest satisfaction, likely because they have not experienced the financial benefit of a full year's participation. • **Demographic Variance:** TVP satisfaction appears somewhat lowest in Western NS and among lower income households. • **Application Process:** The ToU application process has maintained a high level of satisfaction among new joiners across key metrics compared to 2024, while CPP is experiencing a decrease in the clarity of the information provided. While most indicate satisfaction with the amount of information, there is a desire from some to have more information about rates and potential savings.
Understand billing preferences and improvement areas	• **Bill Clarity:** CPP and ToU participants are increasingly struggling to understand their bills and the impact of their participation in pilot programs. In 2025, fewer than one-half of ToU participants now agree the power bill they received was as expected. • **Billing Needs:** Participants are attentive to their bills, noting higher-than-normal prices, requesting savings comparisons, more details, or more time to review the data.
Determine opinions about communication from NSP	• **Satisfaction with Communication:** CPP participants continue to be more satisfied with communication than ToU participants, although results for both pilots are consistent with 2024 results. Reminders, emails, and time of day charts are viewed as the most helpful communication received by pilot participants. • **Contacting Customer Care:** Among the few participants contacting customer care, there has been a decrease in the number of CPP participants looking for program details and an increase in CPP inquiries about billing/savings. ToU participants are still reaching out with saving and billing inquiries and to get more program details. About one in five participants who contacted the Customer Care Center indicate they were left unsatisfied with their experience.
Understand Impact of TVP Participation on Behaviours	• **Changing Behaviours:** Mostly consistent year-over-year, participants state they are likely to change when they wash their clothes, run their dishwasher, and keep lights turned off because of their participation in TVP pilots. Three-quarters of participants state they have, in some way, changed their electricity use after joining the pilot program. • **Installing Products:** Since the pilot began, only three in ten participants have installed any energy-efficient or smart technology.

Summary of Objectives and Key Findings

Objectives	Key Findings
Collect Feedback on the Critical Peak Pilot	• **Communication:** Nearly all CPP participants received peak events notifications, with half leveraging text messages. Email and text are the preferred channels for receiving critical peak event notifications, though there is opportunity to further promote text notifications to participants. Participants would welcome the option to send alerts to additional members of their household. • **Critical Peak Notifications:** Overall, CPP participants appear satisfied with notifications and the timing at which they are received, although satisfaction has decreased this year. The biggest suggestion for improvement would be more advanced notice. • **Number of Events Called:** Feelings toward the number of peak events called in 2025 are generally positive. Participants react positively to cancelled peak events, likely because they count toward the number of max events that can be called without requiring action. • **Awareness of Peak Event Timing:** 2025 saw an increase in the number of participants showing they understand when peak events can be called, though some participants remain unclear. • **Proposed Changes:** One in four participants are at least somewhat likely to leave the CPP pilot if peak events were to be called year-round. The majority of participants feel strongly that the pilot remain the same.
Collect Feedback on the Time-of-Use Pilot	• **Awareness of Peak Hour Timing:** This year marks a significant improvement in awareness of when peak hours are in effect, but improving awareness might lead to higher satisfaction since some participants think hours are in effect longer than they actually are. • **Proposed Changes:** ToU participants are very opposed to possible changes to the pilot, preferring that peak periods continue to avoid weekends, holidays, and the April to October months. One in three ToU participants are at least somewhat likely to leave the ToU pilot should any changes occur, regardless of additional incentives offered. Forced to choose an incentive if program changes occur, most prefer a lower Winter Peak Rate, followed by a lower Winter Off Peak Rate. Interest in a very low Super Off Peak Rate overnight was marginal.
Explore Pricing Plan Preferences and Motivations	• **Motivations for Joining:** Saving money dominates as the main reason for joining and remaining in a rate plan, distantly followed by non-monetary motivations. • **Likelihood of Switching:** Fewer than one in five participants would consider switching to an alternate TVP pilot.

NARRATIVE RESEARCH

Detailed Findings

Satisfaction



Satisfaction with Time-Varying Pricing Rate Pilot

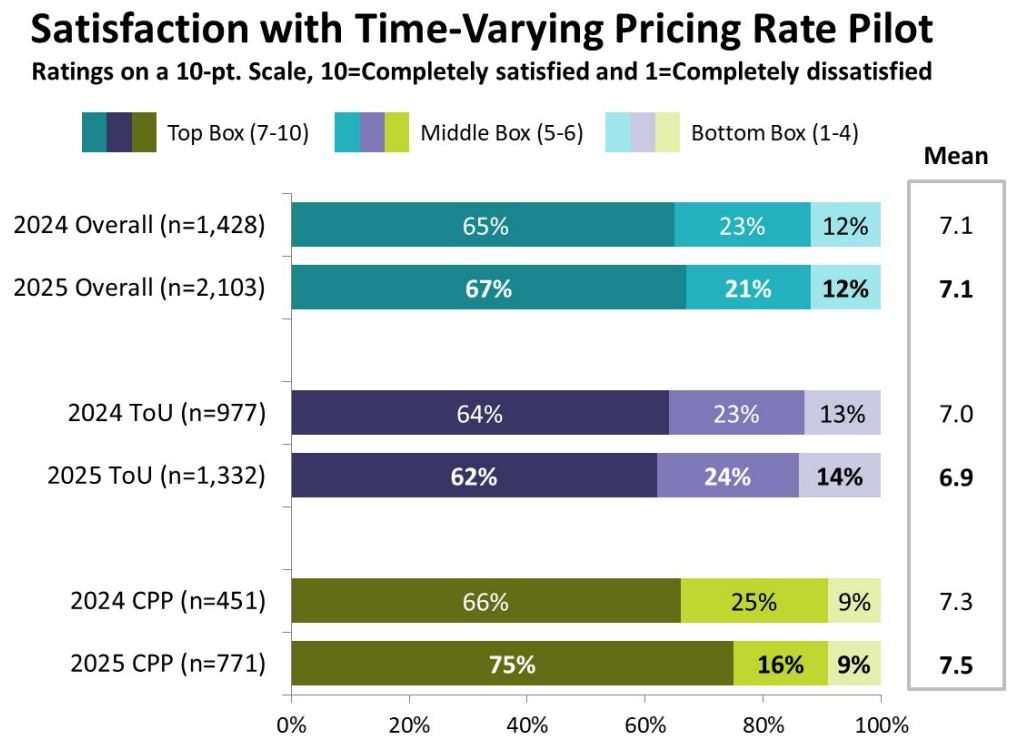
Participant satisfaction with CPP has increased in 2025 while ToU satisfaction has remained relatively stable, with only a slight numerical decline.

Overall satisfaction with the Time-Varying Pricing Rate Pilot (TVP) is consistent from 2025, with top 4 box scores increasing by two points. The number of detractors, or those offering bottom 4 box scores, has remained stable from 2024, at 12%, indicating that overall, there is broad satisfaction among participants.

Top 4 satisfaction with the Critical Peak Rate Pilot (CPP) climbed to 75% (up 9 points). Scores continue to be higher among those who have been in the program for longer (Year 1 – 87%; Year 2 – 84%; and Year 3 – 81%) compared to those joining in the Fall of 2024 (Year 4 – 71%). These results reinforce a previous theory that recent joiners have not been in the pilot long enough to observe the benefits of participation and/or how to best take advantage of it, while those who like the program continue to stay with it over time.

ToU satisfaction meanwhile saw a numerical decrease in top 4 box scores (62%, down 2 points). Mirroring CPP results, ToU satisfaction increases depending on the pilot participant's duration in the program (Year 1 – 83%; Year 2 – 80%; Year 3 – 69%; and Year 4 - 56%)

MyEnergy Insights (MEI) users are more likely to provide higher top 4 box scores for both programs than non-users, signalling that continuing to promote the platform to participants can increase overall satisfaction. Top 4 box satisfaction for CPP was 78% for MEI users and 64% for non-users while ToU participant satisfaction was 64% for MEI users and 58% for non-users. (Table 24b)

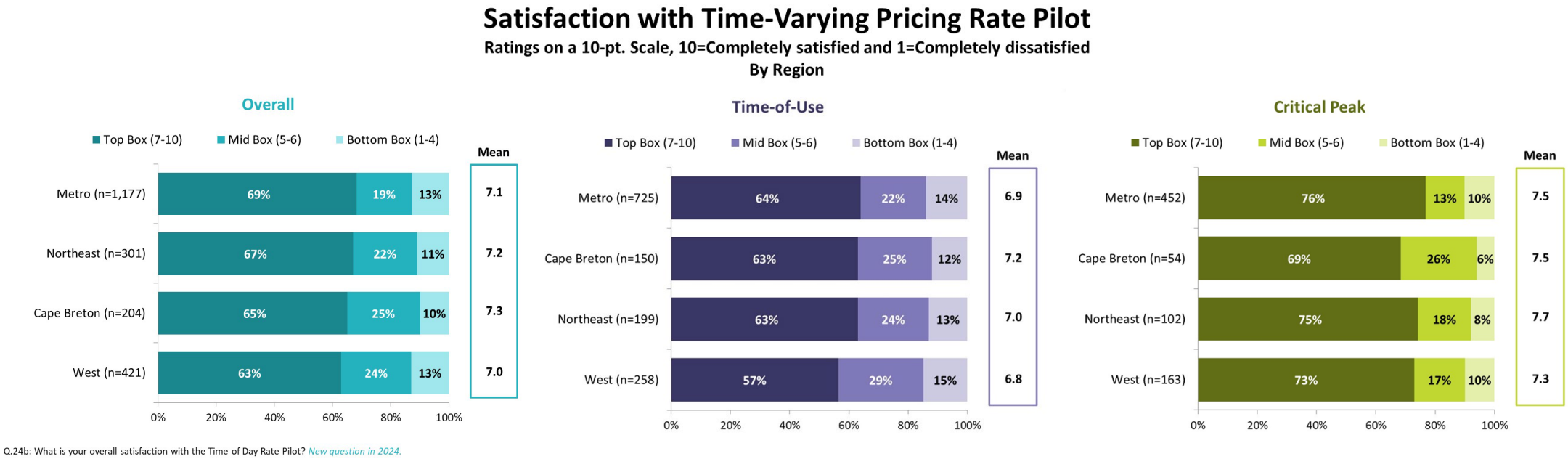


Q.24b: What is your overall satisfaction with the Time of Day Rate Pilot? *New question in 2024.*

Satisfaction with Time-Varying Pricing Rate Pilot - Region

Overall satisfaction with the TVP Rate Pilots appears to be somewhat lower in Western Nova Scotia compared to Metro. Variation in results are driven mostly by ToU participants while CPP participant satisfaction appears more consistent across the province.

Comparing satisfaction results across the provinces, overall TVP pilot participant satisfaction is significantly lower in Western Nova Scotia compared to Metro. While smaller sample sizes prevent confidence in a statistical variation for the individual pilots, Western Nova Scotia participants appear to be at least somewhat less satisfied with ToU, likely driven by the higher number of participants in that region indicating electricity as primary, secondary, or tertiary heat source (91%) compared to the rest of the province (NE – 83%; Metro – 83%; CB – 85%). CPP participant satisfaction is more consistent across the province. (Table 24b)

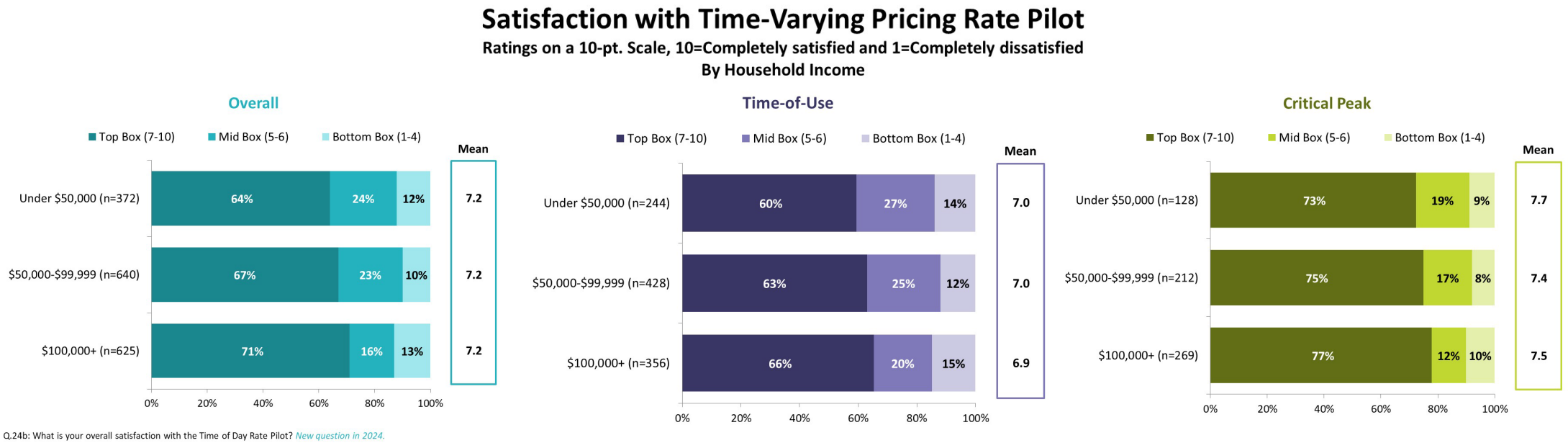


Q.24b: What is your overall satisfaction with the Time of Day Rate Pilot? *New question in 2024.*

Satisfaction with Time-Varying Pricing Rate Pilot – Household Income

Satisfaction with TVP pilots are relatively consistent across income brackets, though there an indication of a slight correlation between household income and satisfaction.

Overall, TVP participants with a household income of >$100,000 are significantly more likely than those <$50,000 to provide top 4 box scores when indicating their satisfaction with the pilot, indicating that there is at least a slight relationship between satisfaction and income. Results suggest those in higher income categories give a wider range of scores while participants from lower income categories are more concentrated around the mean. A closer look, however, indicates little variation in mean scores, both overall and between the two pilot programs. Additionally, while satisfaction does increase incrementally across income categories for ToU and CPP, the increases are numerical only (due to the smaller sample sizes). (Table 24b)

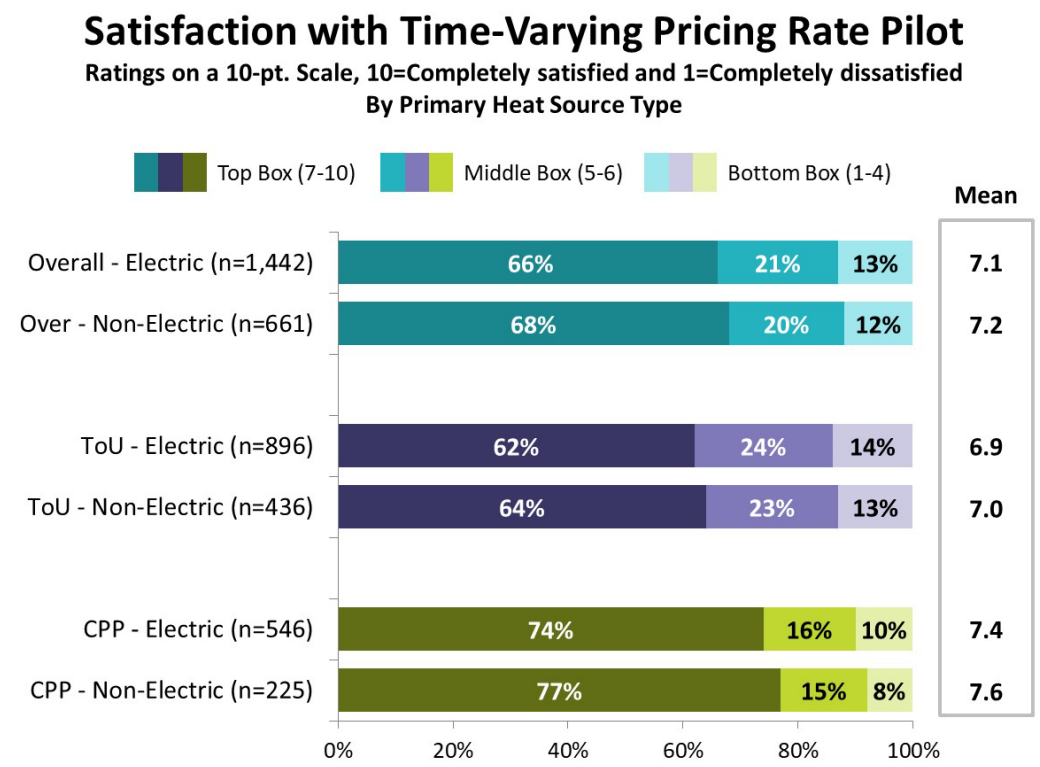


Q.24b: What is your overall satisfaction with the Time of Day Rate Pilot? *New question in 2024.*

Satisfaction with Time-Varying Pricing Rate Pilot – Primary Heat Source Type

Satisfaction among CPP and ToU participants does not vary significantly between those relying on electricity as their primary heat source and those who are not.

Looking at satisfaction results based on participants' primary heat source shows little variation between those on electric vs non-electric heat sources. Results are relatively consistent overall, and for both ToU and CPP pilots. Results suggest that those on electric heat may be identifying ways to still realize savings while participating the program, such as turning heat off or down during peak events and peak hours. (Table 24b)



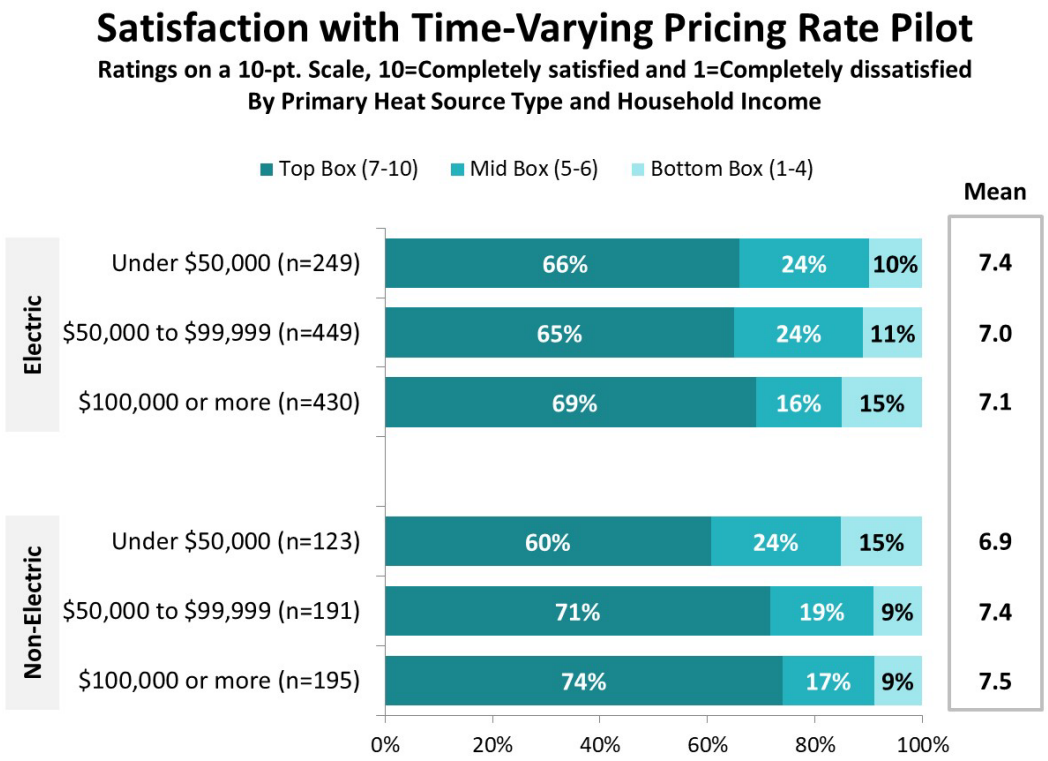
Q.24b: What is your overall satisfaction with the Time of Day Rate Pilot? *New question in 2024.*

Satisfaction with Time-Varying Pricing Rate Pilot – Household Income & Heat Source

Satisfaction with TVP rate pilots, overall, appears to improve with household income across non-electric participants.

Reviewing satisfaction results across household income and heat source suggests that TVP participants on non-electric heat sources with lower incomes are significantly less satisfied than those on non-electric heat sources with household incomes greater than $50,000. The same cannot be said for participants on electric heat sources, where satisfaction is consistent across household incomes.

There are also no significant differences in satisfaction between income categories between participants on each heat source (e.g., those with household incomes >$100,000 on non-electric heat offer similar scores to those in the same income bracket on electric heat). That said, there are some numerical differences, suggesting that a larger sample may help to confirm or refute a correlation. (Table 24b)

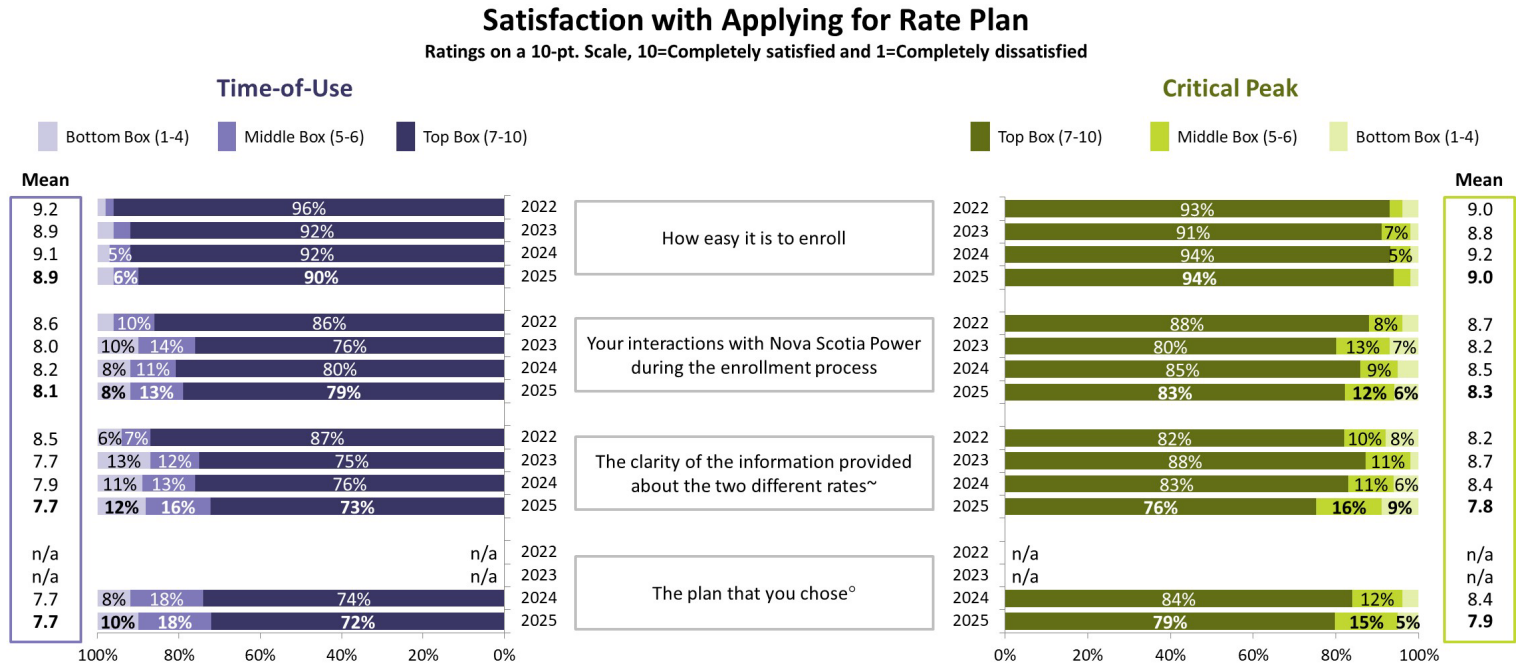


Q.24b: What is your overall satisfaction with the Time of Day Rate Pilot? *New question in 2024.*

Application Process

The ToU application process has maintained a high level of satisfaction across key metrics compared to 2024, while CPP sees a decrease in the clarity of the information provided.

The majority of those entering the ToU and CPP pilots in November 2024 (Year 4 participants) are satisfied with the process of enrolling. Satisfaction remains highest for the ***ease of enrollment*** and ***interaction with Nova Scotia Power*** for both pilots. This year, CPP saw a significant decrease in the number of participants providing top 4 box scores for the ***clarity of information provided about the two rates*** (76%; down 7 points) and a numerical decrease in the number of people indicating ***satisfaction with the plan they chose*** (79%; down 5 points). (Tables 4a, c-e)



Q.4a, c-e: **[AMONG YEAR 2 PARTICIPANTS ONLY IN 2023/YEAR 3 PARTICIPANTS ONLY IN 2024/YEAR 4 PARTICIPANTS ONLY IN 2025]*** According to our information, you joined the [Time-of-Use/Critical Peak] rate plan in [2023: Fall 2022/2024: Fall 2023/2025: Fall 2024].** Thinking back to when you applied for the [Time-of-Use/Critical Peak] rate plan, please rate your level of satisfaction with each of the following. (Time-of-Use – 2022: n=428; 2023: n=137; 2024: n=665; 2025: n=872. Critical Peak – 2022: n=174; 2023: n=58; 2024: n=307; 2025: n=528) **Skip added in 2023/2024/2025. **Additional question wording added in 2023. ~Wording change in 2023. Responses of 4% or less are represented by bar. °New question in 2024.*

Additional Information or Materials When Deciding to Enroll

While most indicate satisfaction with the amount of information, there is a desire from some to have more information on rates and potential savings.

Asked what additional information or materials would have been helpful in applying for the program, seven in ten participants say either nothing (40%) or they are unsure (30%). The top mention among the remaining participants include *more information on rates/savings/billing* (16%; up 4 points). (Table 5)

> *"Prior studies and statistics on **expected average changes in rate charges for a household based on clear definitions of what household usage is.**" – ToU Year 4 Participant*

> *"**I can see the issues with doing this, but if there was a way to give people a sense of the potential $ implications.** I did my own calculations and talked to neighbors who were already enrolled to find out how it went for them in the place of this, but that took some time and effort and I might have not bothered enrolling if I couldn't take those extra steps myself." – ToU Year 4 Participant*

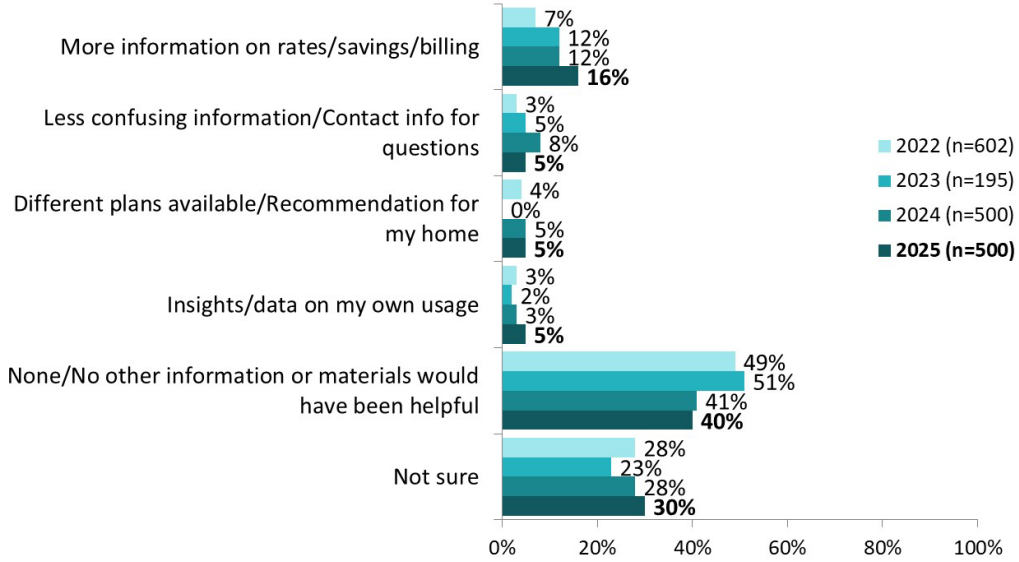
> *"**I was not aware that Critical use could be called on Sunday evenings** when families were preparing for the week and would be having weekly family dining." – CPP Year 4 Participant*

> *"I knew when there would be critical peak events and I knew when I could use appliances that required higher energy output. **What I didn't know was what I saved or the benefits of sticking with the program.**" – CPP Year 4 Participant*

What Additional Information or Materials Would Have Been Helpful in Deciding to Apply for Time-Varying Pricing Rate Pilot

Key Unaided Mentions

Overall



Q.5: **[AMONG YEAR 2 PARTICIPANTS ONLY IN 2023/YEAR 3 PARTICIPANTS ONLY IN 2024/YEAR 4 PARTICIPANTS ONLY IN 2025]*** What, if any, additional information or materials would have been helpful to receive when you were deciding to apply for the Time-of-Day Rate Pilot? **Skip added in 2023 and 2024. In 2024 and 2025 this table includes 500 randomly coded responses.*

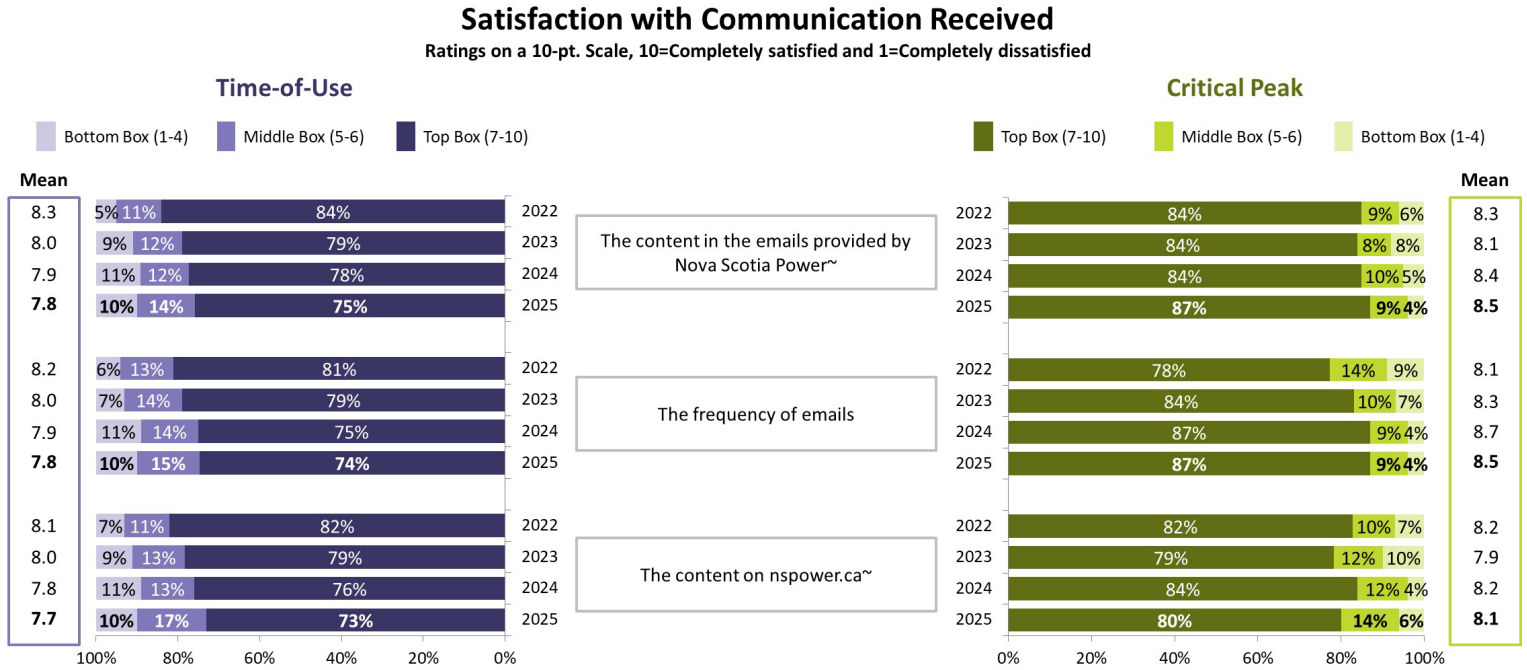
Communications



Satisfaction with Communications

CPP participants continue to be more satisfied with pilot communication than ToU participants, although results for both pilots are consistent with 2024 results.

Satisfaction with email content, content on nspower.ca, and the frequency of emails has remained consistent for ToU and CPP from 2024, with no significant differences in top 4 box scores. CPP participants are somewhat less likely to be satisfied with the content on nspower.ca, signaling an opportunity to improve online content for those looking for additional information. Meanwhile, ToU participant satisfaction is consistent across the three communications metrics, although results are lower than CPP satisfaction. (Tables 6a-c)



Q.6a-c Thinking back to the communication you have received as part of this pilot, please rate your level of satisfaction with each of the following. (Time-of-Use – 2022: n=428; 2023: n=445; 2024: n=977; 2025: n=1,332. Critical Peak – 2022: n=174; 2023: n=178; 2024: n=451; 2025: n=771) *~Wording change in 2023.*

Most Helpful Communication

Reminders, emails, and time of day charts are viewed as the most helpful communication received by pilot participants.

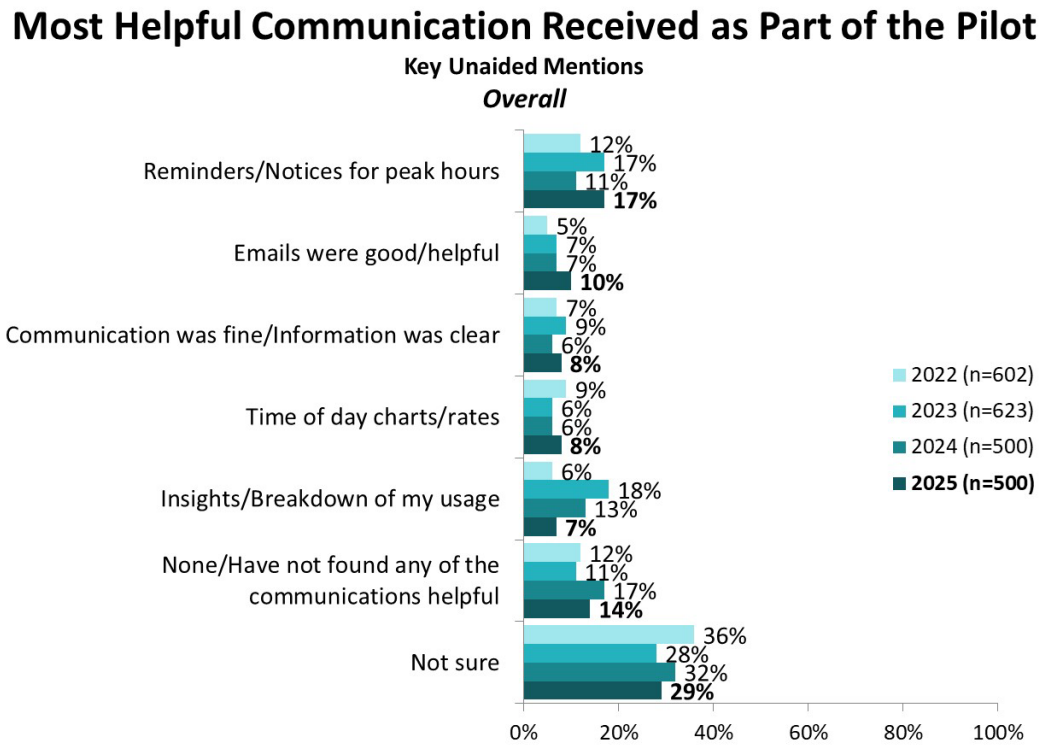
Asked about the most helpful communication they have received as part of the pilot, participants focused on *reminders/notices for peak hours* (17%; up 6 points), *emails were good/helpful* (10%; up three points), and *time of day charts/rates* (8%, up 2 points). (Table 7)

> *"**The reminders that a critical event was about to happen**. Sometimes the prior day's email would get lost in the amount of "junk" email I receive so the reminder early in the day was beneficial." – CPP Year 4 Participant*

> *"Helpful that they will send both an email and a text message for an event**. I have the email sent to me and the text message sent to my wife so we both know when an event is taking place.**" – CPP Year 3 Participant*

> *"**Rates and times were clearly explained, from which I made a chart for my home reference.** Received a one-page card in the mail with it clearly outlined." – ToU Year 3 Participant*

> *"The "warning" of the percentage we used part way through the billing cycle, the graphic showing the percentage of use (always plugged in, laundry, stove etc.) and **the reminder email that the peak season ended April 1. I forgot**!" – ToU Year 3 Participant*

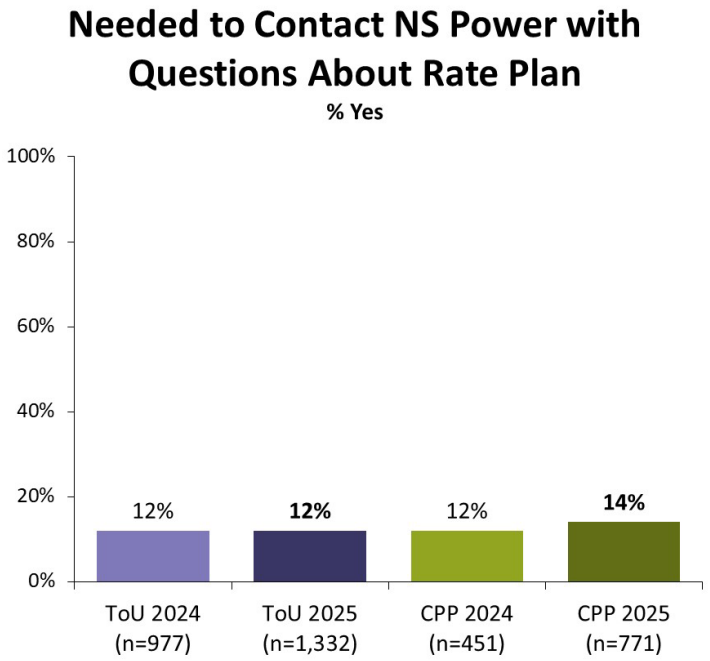


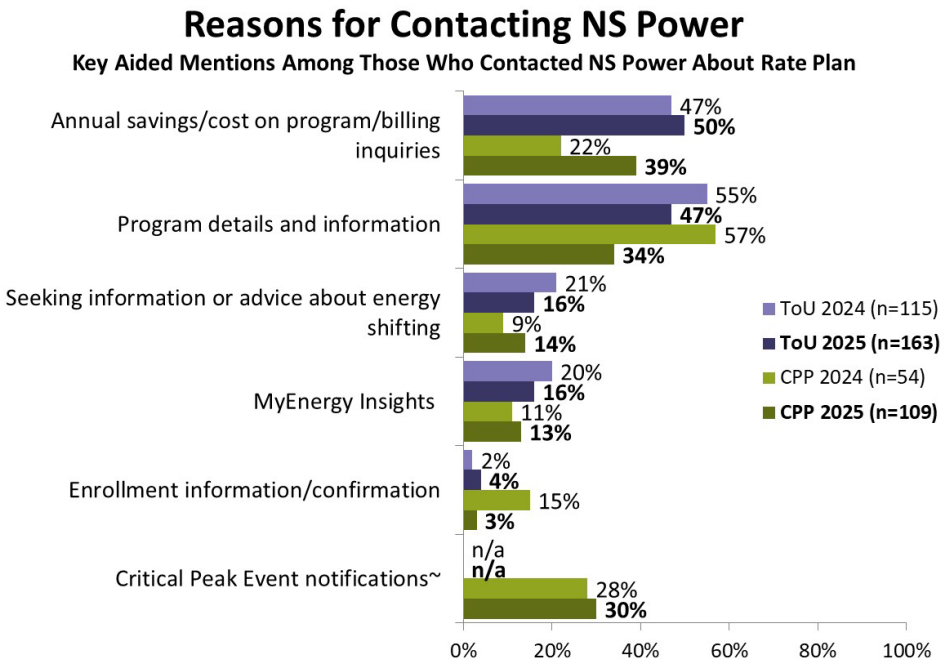
Q.7: Again, regarding the communication you have received as part of participating in this pilot, what have you found most helpful? *In 2024 and 2025 this table includes 500 randomly coded responses.*

Contact with Customer Care Centre

Among the minority of participants contacting customer care, there has been a decrease in CPP participants looking for program details and an increase in CPP inquiries about billing/savings. ToU participants are still reaching out with saving and billing inquiries and to get more program details.

Just over one in ten TVP participants needed to contact NSP's Customer Care Centre with questions about their rate plan. This year saw an increase in the number of CPP participants calling about ***annual savings/costs/billing*** (39%; up 17 points) and a decrease in those calling for ***program details and information*** (34%; down 23 points). (Tables 7b and 7c)



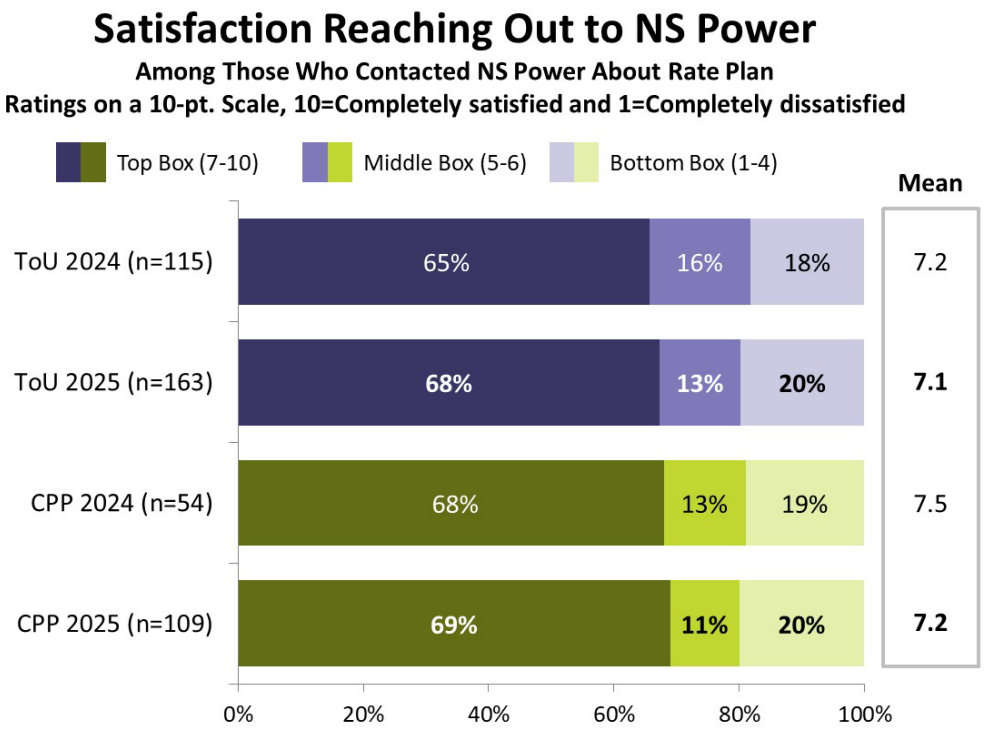


Q.7b: Did you need to contact Nova Scotia Power regarding any questions about the [Time-of-Use/Critical Peak] rate pilot? | Q.7c: **[IF YES IN Q.7B]** When you called Nova Scotia Power, what specifically did you contact them about? *New questions in 2024. Slight question wording changes in 2025. ~Among CPP customers only.*

Satisfaction with Customer Care Experience

The majority of participants who contacted the Customer Care Center indicate they were satisfied with their experience.

Among the 272 participants who contacted the Customer Care Center, one in five indicate they were left unsatisfied with their experience, consistent with 2024 results. Results are consistent across both pilots, with seven in ten offering top 4 box scores. (Table 7d)



Q.7d: **[IF YES IN Q.7B]** How satisfied were you with the experience you had reaching out to the Customer Care Center about the [Time-of-Use/Critical Peak] rate plan? *New question in 2024. Slight question wording change in 2025.*

Communications: Critical Peak Events



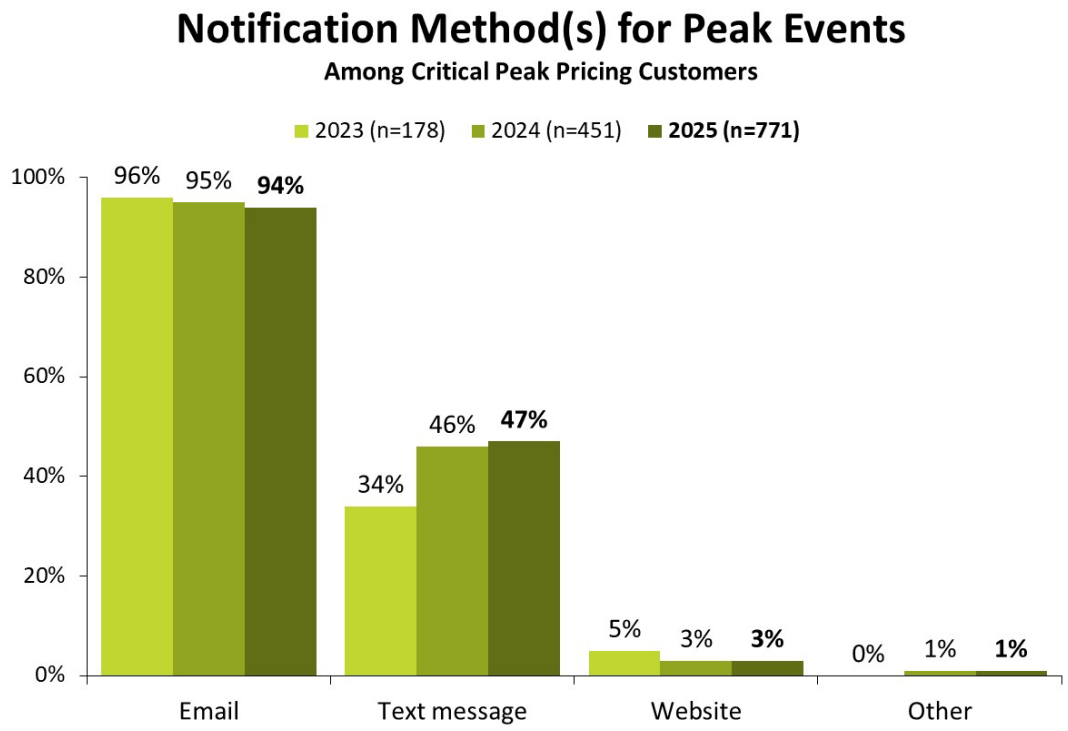
Notification Methods for Peak Events

Nearly all CPP participants received peak events notifications, with half leveraging text messages.

Virtually all CPP participants continue to receive peak event notifications via ***email*** (94%; down 1 point) and a consistent number of participants receiving ***text messages*** (47%; up 1 point).

Year 1 participants continue to be less likely to receive notifications by text message, further indicating an opportunity to promote text message notifications to those who have been in the program for longer.

MyEnergy Insights users are more likely to receive text messages than those who do not use the platform. (Table 10b)



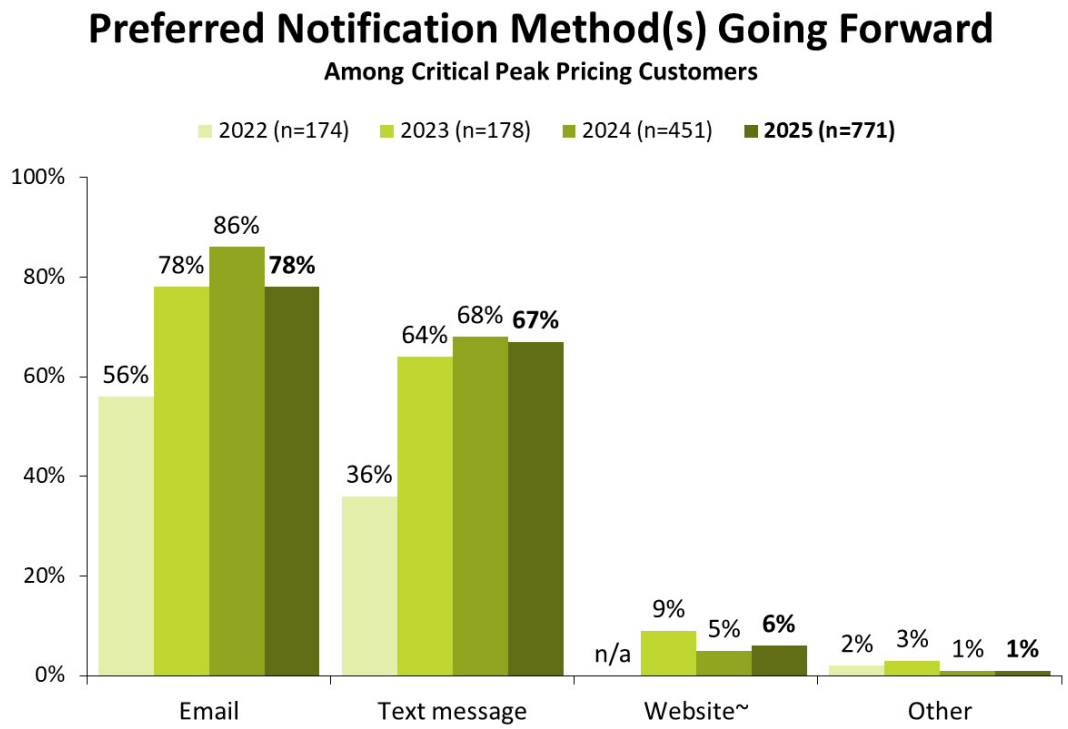
Q.10B: **[IF CRITICAL PEAK PRICING CUSTOMER]** What method(s) do you receive notifications of Peak Events from Nova Scotia Power? *New question in 2023.*

Preferred Notification Method

Email and text are the preferred channels for receiving critical peak event notifications, though there is opportunity to promote text notifications to participants.

Eight in ten CPP participants express a preference for ***email*** notifications (78%; down 8 points) followed by seven in ten who prefer notifications by ***text message*** (67%; down 1 point). While 67% of participants would prefer text message notifications, only 47% indicate currently receiving them, highlighting a potential opportunity to educate participants about signing up for text alerts.

MyEnergy Insights users are more likely to express a preference for text messages over non-users. (Table 10)

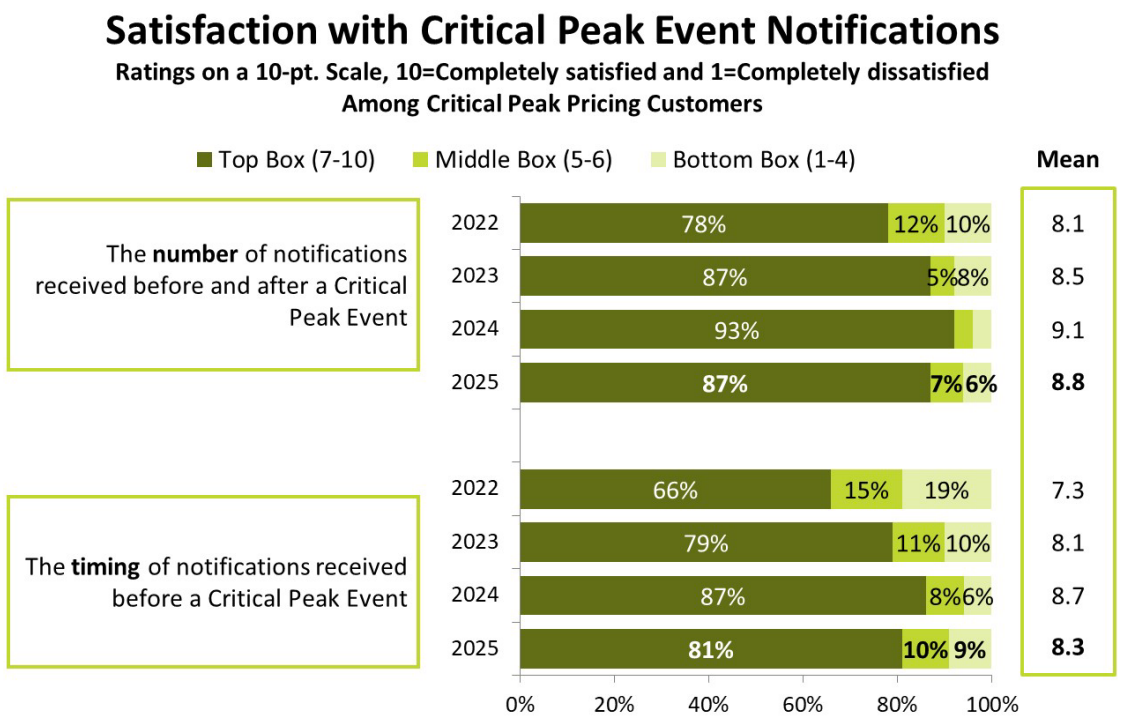


Q.10: **[IF CRITICAL PEAK PRICING CUSTOMER]** What method(s) would you prefer Nova Scotia Power to use to send notifications of these peak events going forward? *~New option in 2023.*

Critical Peak Notifications

Overall, CPP participants appear satisfied with of notifications and the timing at which they are received, though satisfaction has decreased this year.

This year, CPP participants appear slightly less satisfied (top 4 box) with the *number* of notifications received before and after a peak event (87%; down 6 points) and the *timing* of notifications received before a peak event (81%; down 6 points). (Tables 8a-b)

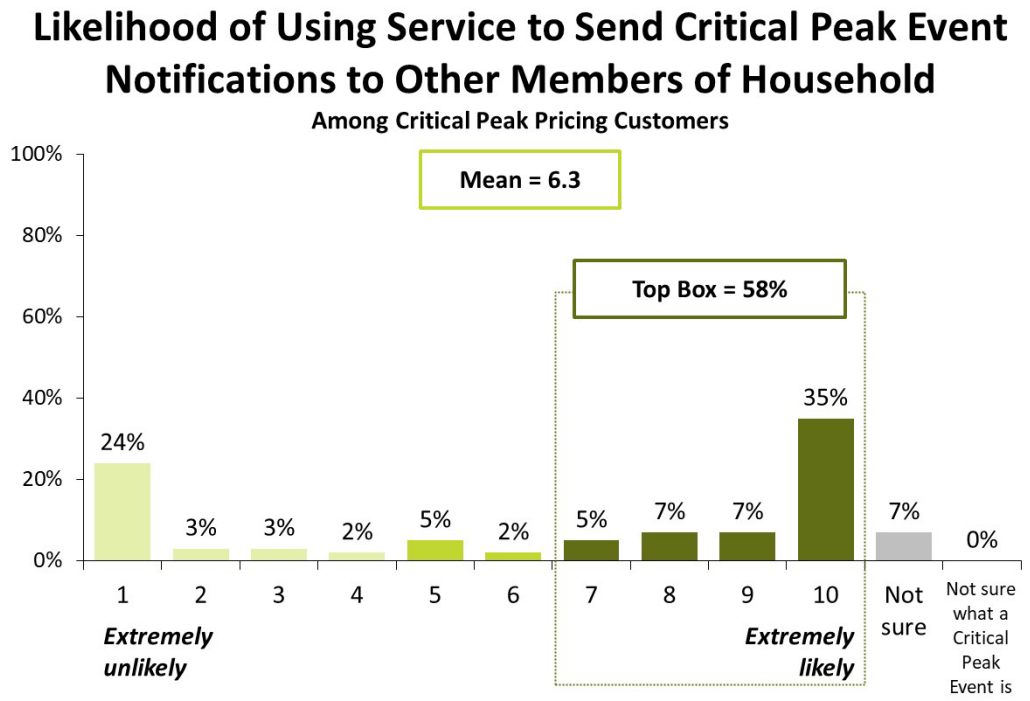


Q.8a-b: **[IF CRITICAL PEAK PRICING CUSTOMER]** NS Power aims to send the right number of Peak Event notifications at the times they would be most useful to you. How satisfied are you with each of the following? (2022: n=174; 2023: n=178; 2024: n=451; 2025: n=771) *Responses of 4% or less are represented by bar.*

Adding Household Members to Critical Peak Event Notifications

CPP participants would welcome the opportunity to send critical peak event notifications to other members of their household.

If Nova Scotia Power allowed participants to send critical peak event notifications to other household members, over half of CPP participants say they would do so, indicating a broad interest in this capability. Interest is even higher among multi-person households, unsurprisingly, with 76% of households with three or more people expressing interest, compared to 58% of two-family households and 35% of single-family households. (Table Q.8Bb)



Q.8Bb: **[IF CRITICAL PEAK PRICING CUSTOMER]** If Nova Scotia Power allowed you to send Critical Peak Event notifications to other members of your household, how likely would you be to use this service? (n=771) *New question in 2025. Responses of 'Not sure' and 'Not sure what a Critical Peak Event is' are excluded from the calculation of all summary statistics.*

Critical Peak Notification Improvement

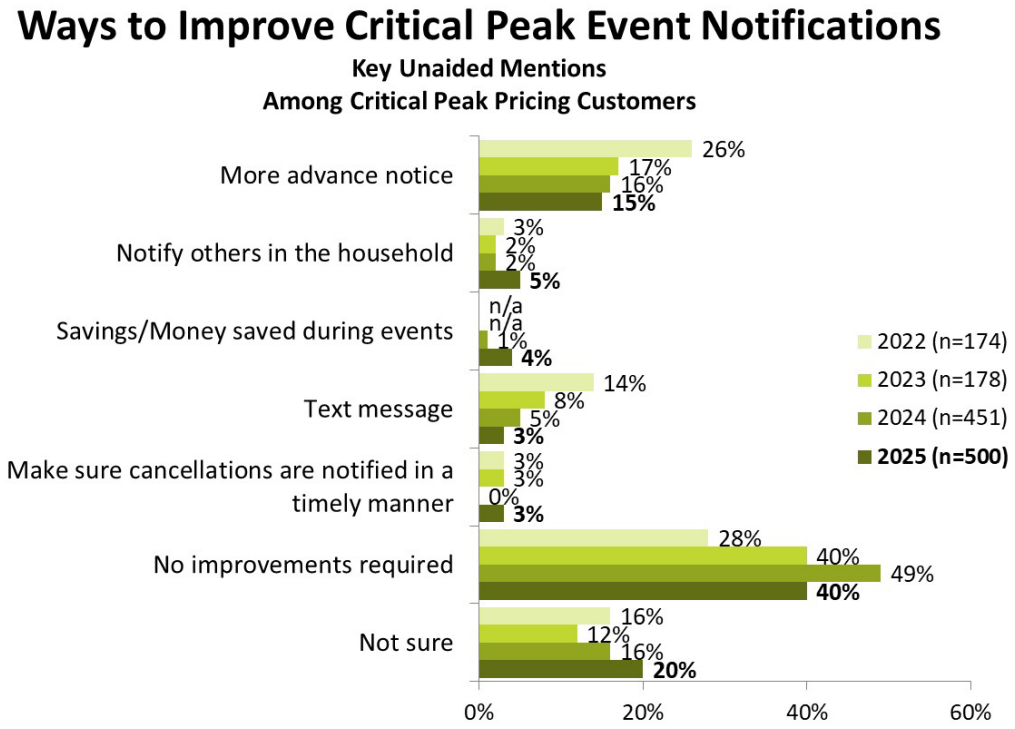
Critical peak notifications could be improved by more advance notice, although most offer no suggestions for improving communication.

When asked about how peak event notifications could be improved, about one in eight mention *more advance notice* (15%: down 1 point) and one in twenty want the option to send notifications to other household members (5%; up 3 points). Three in five participants feel there are *no improvements required* or are unsure. (Table 9)

"Perhaps some suggestions as to how best to optimize the Critical Peak Event e.g. do laundry between the hours of ____ and ___ or reduce your thermostat by ___degree(s). ***Practical suggestions would be a good reminder.*** *" – CPP Year 2 Participant*

"One of my bills clearly indicated that I had been invoiced for a significant amount of energy use during a critical peak period. I was very careful about minimizing energy use during these periods, so I was quite surprised, and unhappy, to see this bill. ***I would have liked to see clear and specific information about which Critical Peak Events (date and time) I was being billed "extra" for****, so that I could compare my invoice against my energy use to confirm the validity of the charge." – CPP Year 4 Participant*

*"****More time in advance would be nice but it's not a critical shortage of notice time****. We always hear by 3 pm whether there's an event the next day. Notice by noon for a 7 am CPP might be helpful some days, but that's just bonus time." – CPP Year 1 Participant*



Q.9: **[IF CRITICAL PEAK PRICING CUSTOMER]** How, if at all, could the Critical Peak Event notifications be improved? *In 2025 this table includes 500 randomly coded responses.*

Pricing Plan Preference: Critical Peak

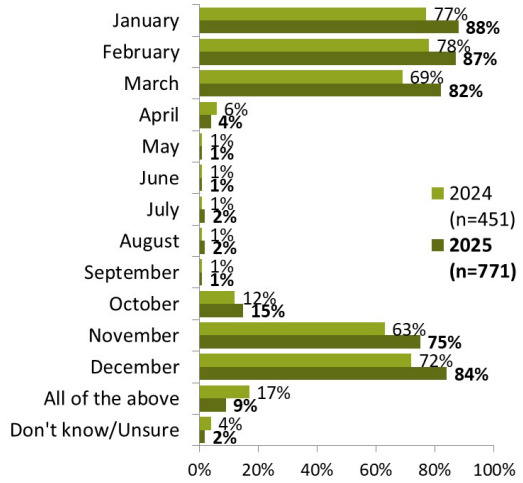


Peak Events

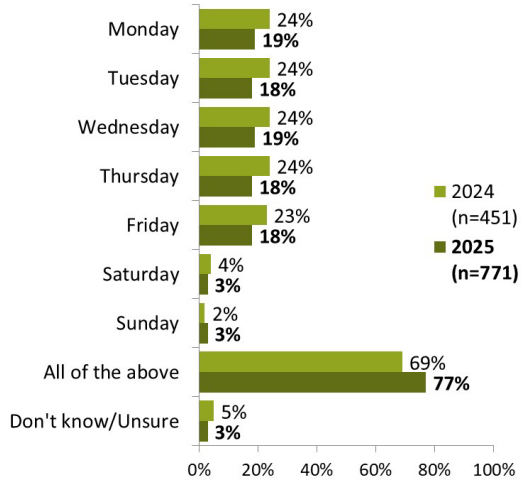
Awareness of when events critical peak events can happen is improving, though some participants remain unclear.

CPP participants were asked when they understood peak events can be called. This year saw an increase in the number of participants showing they understand that peak events can be called from November to March and any day of the week. There is still a minority of participants who do not realize that events can be called on weekends and about one in five believe events can be called at any time of the day. (Tables 11a-c)

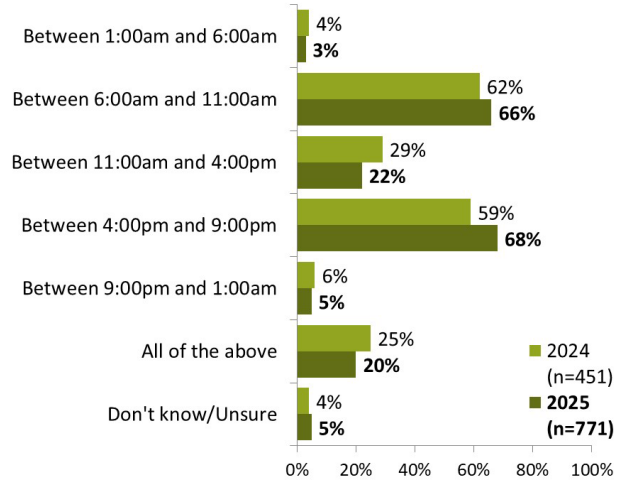
Months a Peak Event Can Be Called
Among Critical Peak Pricing Customers



Days of the Week a Peak Event Can Be Called
Among Critical Peak Pricing Customers



Times of Day a Peak Event Can Be Called
Among Critical Peak Pricing Customers



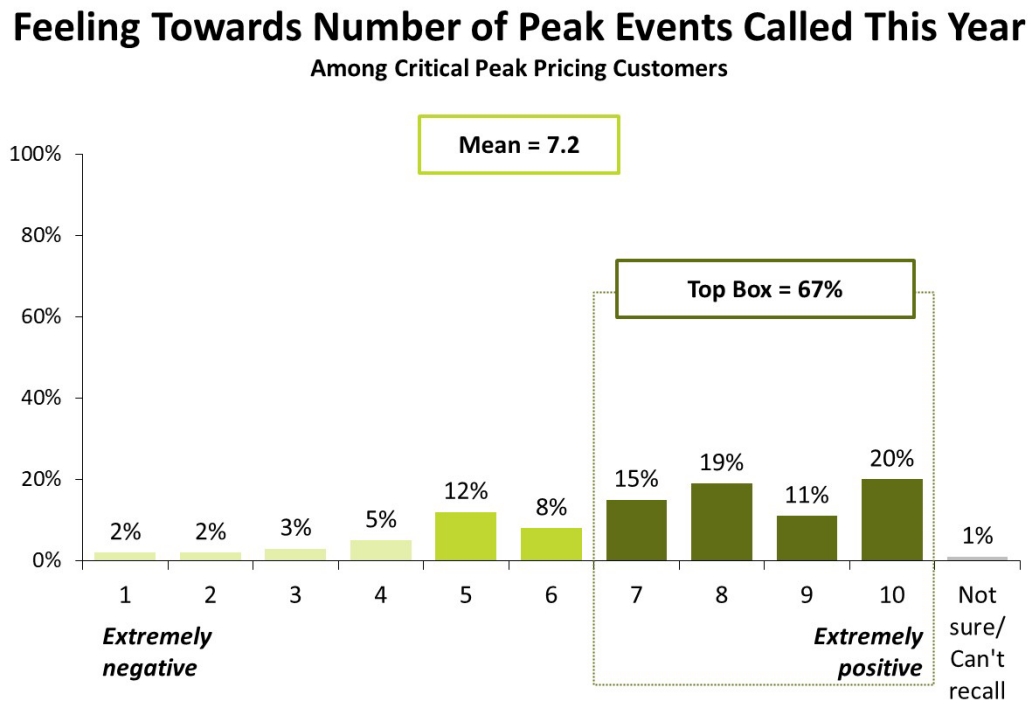
[IF CRITICAL PEAK PRICING CUSTOMER] Q.11a.i: Based on what you know, during which of the following months can a peak event be called? Select all that apply. | Q.11a.ii: Based on what you know, what days of the week can a peak event be called? Select all that apply. | Q.11a.iii: And again, based on what you know, what times of day can a peak event be called? Select all that apply. *New questions in 2024.*

Reaction Toward Number of Peak Events Called in 2025

Feelings toward the number of peak events called in 2025 are generally positive, with just a minority of participants responding negatively.

This year marked the highest number of peak events called in a single year (17 of a possible 18). Despite this, most CPP participants appear unbothered, with two in three reacting positively (67%) and most of the remaining third remaining neutral (21% offering scores of 5-6; 13% offering bottom 4 box scores).

Sentiment around the number of events called does not appear to differ based on tenure in the pilot, although those on non-electric heat sources feel more positive about the number of events than those on electric (74% vs 64%). Feelings are also more positive among one- and two-person households (72% and 71% respectively) compared to households of three or more (58%), possibly indicating the increased difficulty of navigating peak events when additional routines must be accommodated. (Table Q.11.a.v)

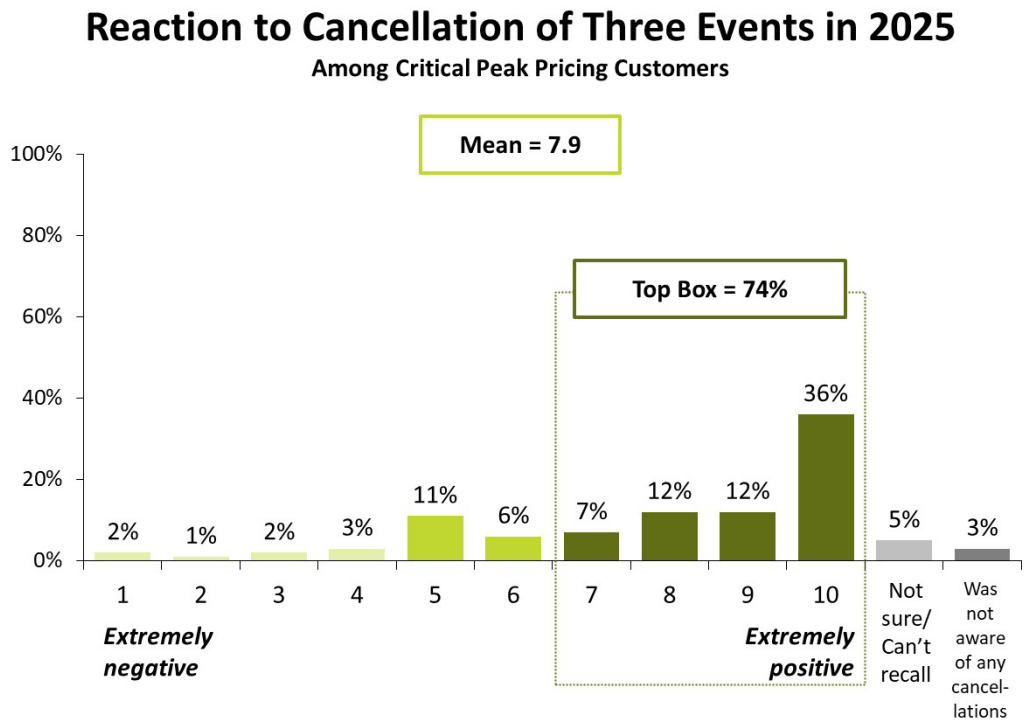


Q.11a.v: **[IF CRITICAL PEAK PRICING CUSTOMER]** How do you feel about the number of peak events called this year? (n=771) *New question in 2025. Responses of 'Not sure/Can't recall' are excluded from the calculation of all summary statistics.*

Reaction to Event Cancellation

Overall, participants react positively to cancelled peak events, likely because they count toward the number of max events that can be called without requiring action.

Asked about their reaction to Nova Scotia Power cancelling three critical peak events this year, participants react favorably, with three in four saying they reacted positively (74%). Reaction to cancelled events was consistent across pilot tenure and key demographics. (Table Q11a.vi)

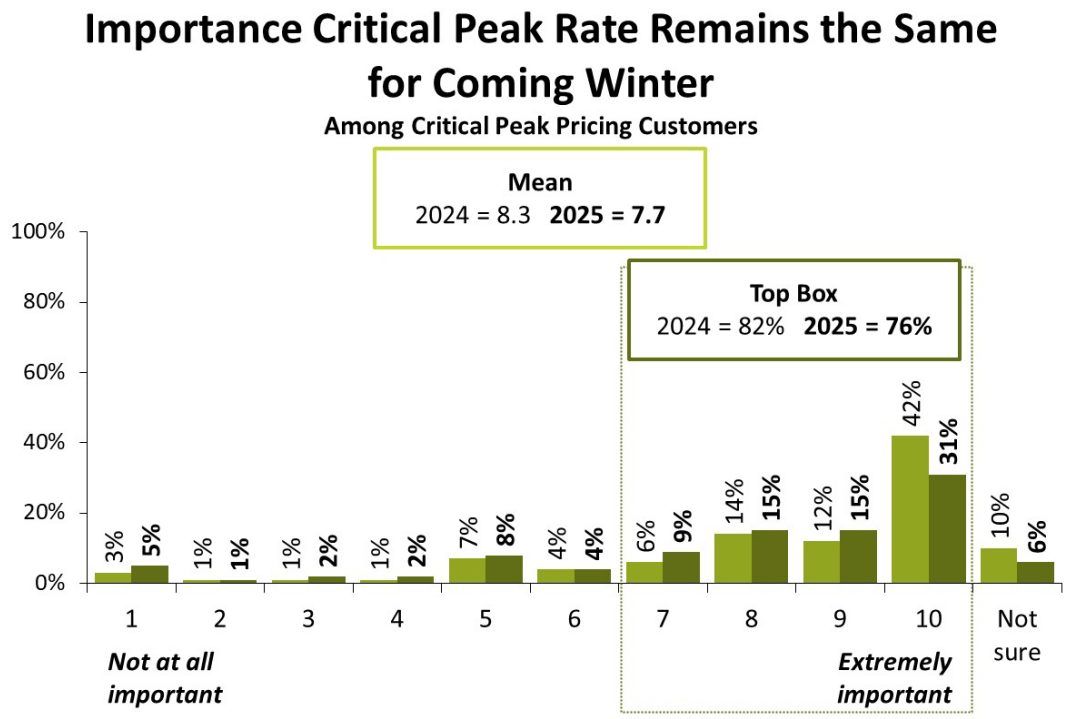


Q.11a.vi: **[IF CRITICAL PEAK PRICING CUSTOMER]** What was your reaction to the Nova Scotia Power issuing cancellations for three events this year? (n=771) *New question in 2025. Responses of 'Not sure/Can't recall' and 'Was not aware of any cancellations' are excluded from the calculation of all summary statistics.*

Importance that Rate Remains the Same This Winter

CPP participants continue to feel strongly that the critical peak rate remains the same in the coming winter.

Asked about the importance that the rate remains the same for the coming winter, three in four participants give high scores (76%), although there is a notable drop in the number providing a top box score (31%; down 11 points). (Table 11b.i)

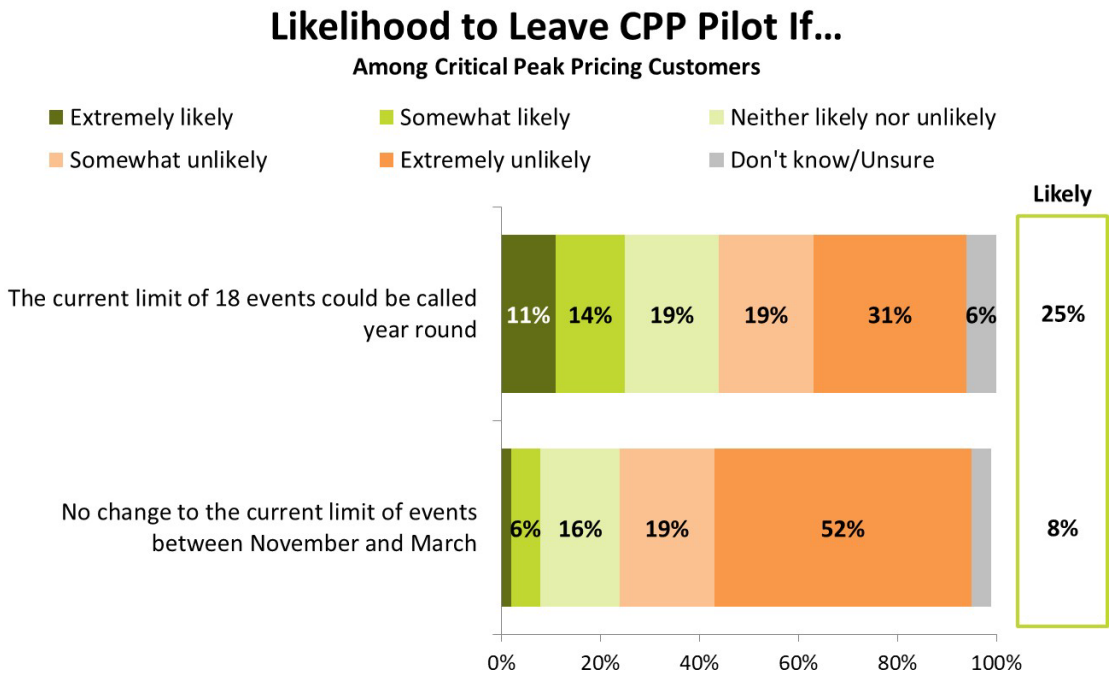


Q.11b.i: **[IF CRITICAL PEAK PRICING CUSTOMER]** How important is it to you that the Critical Peak rate remain the same for the coming winter season (from November 1, [2024/2025] to March 31, [2025/2026]? (2024 n=451, 2025 n=776) *New question in 2024. Responses of 'Not sure' are excluded from the calculation of all summary statistics.*

Likelihood of Leaving the CPP Pilot

One in four participants are at least somewhat likely to leave the CPP pilot if peak events can be called year-round.

Presented with two scenarios that may impact their participation in the program, one in four participants indicate they would be at least somewhat likely to leave the CPP pilot if the current limit of 18 events could be called year-round (25%) compared to half who would be at least somewhat unlikely to leave (50%). In contrast, only a minority of participants say they are likely to leave the program without any changes to the current limit of events (8%). (Tables Q11Ea-b)



Q.11Ea-b: **[IF CRITICAL PEAK PRICING CUSTOMER]** How likely would you be to leave the CPP pilot if… (n=771) *New questions in 2025. Responses of 4% or less are represented by bar.*

Pricing Plan Preference: Time-of-Use

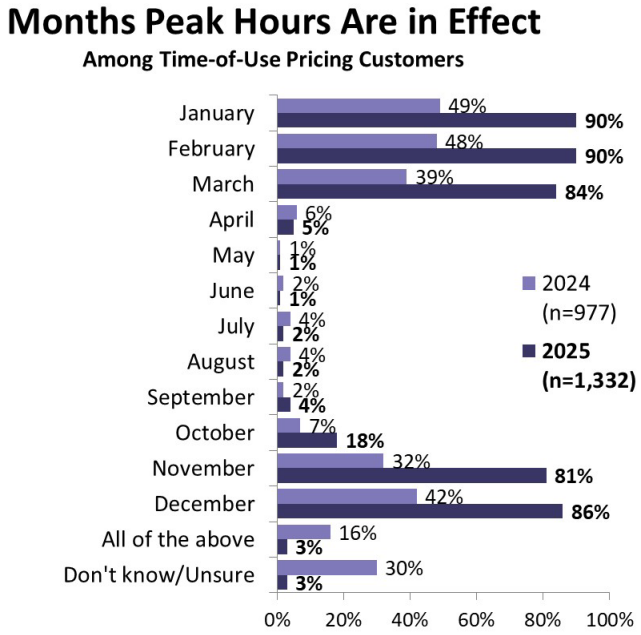


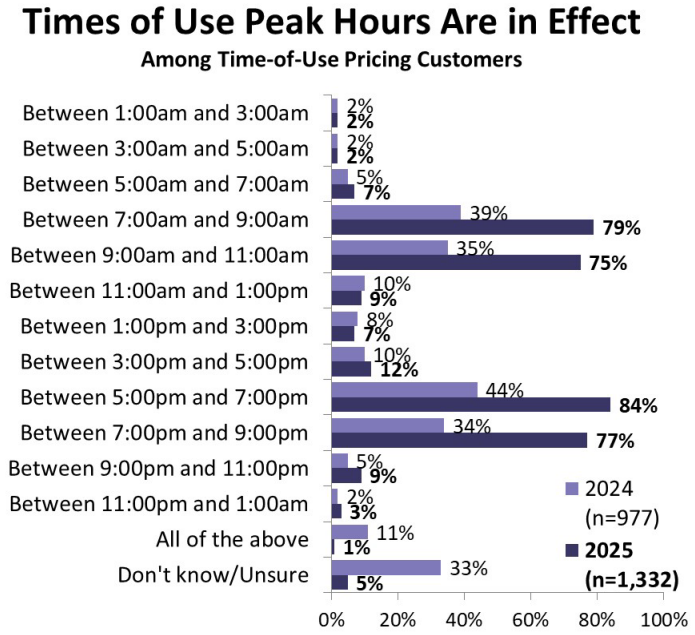
When Time-of-Use Peak Events Can Be Called

This year marks a significant improvement in awareness of when peak hours are in effect, but improving awareness might lead to higher satisfaction since some participants think hours are in effect longer than they actually are.

ToU participants are increasingly aware of when peak hours are in effect, with the majority correctly citing November through March. One in five still believe events can be called in October, signaling that the November start could be emphasized a bit more in marketing. (Table 12a)

Participants are also increasingly knowledgeable about what times of day peak hours are in effect, with the bulk indicating between 7am – 11am and 5pm – 9pm. Some think peak hours are the hours in between, indicating that despite significant progress, there continues to be opportunity to further educate participants about ToU hours. (Table 12b)





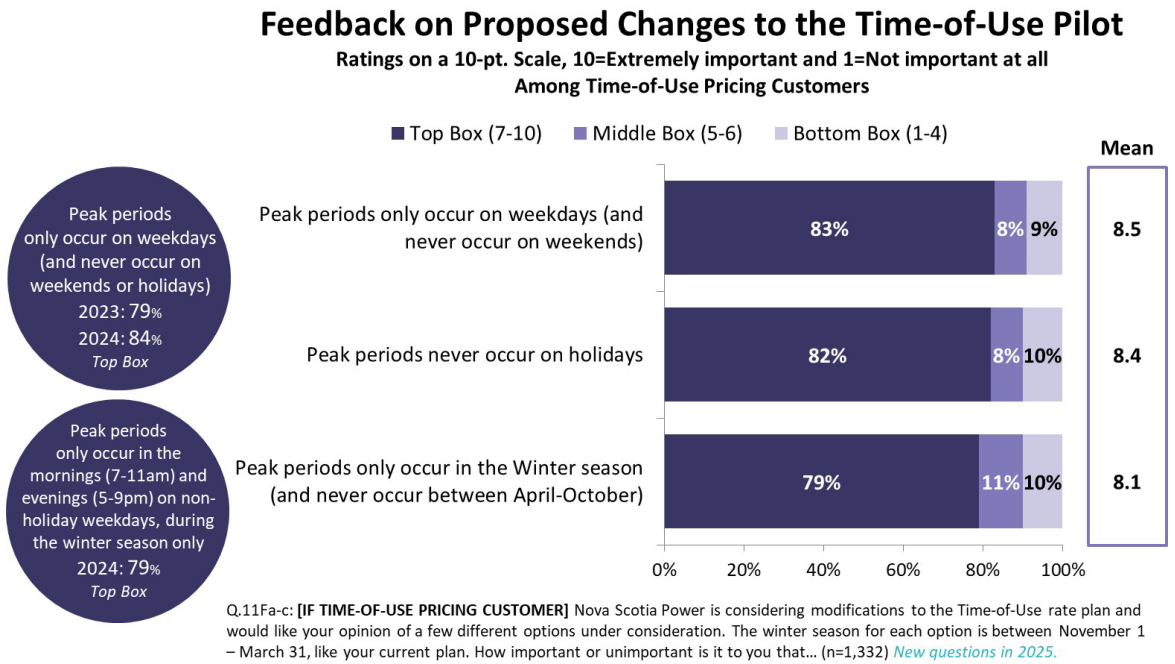
[IF TIME-OF-USE PRICING CUSTOMER] Q.12a: Based on what you know, during which of the following months can a peak event be called? Select all that apply. | Q.12b: And again based on what you know, what times of day can a peak event be called? Select all that apply. *New questions in 2024.*

Feedback on Proposed Changes to the Time-of-Use Pilot

ToU participants are very opposed to possible changes to the pilot, preferring peak periods continue to avoid weekends, holidays, and the April to October months.

It is incredibly important to ToU participants that peak periods only occur on weekdays, never occur on holidays, and only in the Winter season. One-half or more of participants give a score of 10 out of 10, indicating that all three scenarios are *extremely* important, with four in five participants saying that each area remain unchanged (top 4 box).

Importance is consistent across participation years 1-4. (Tables 11Fa-c)

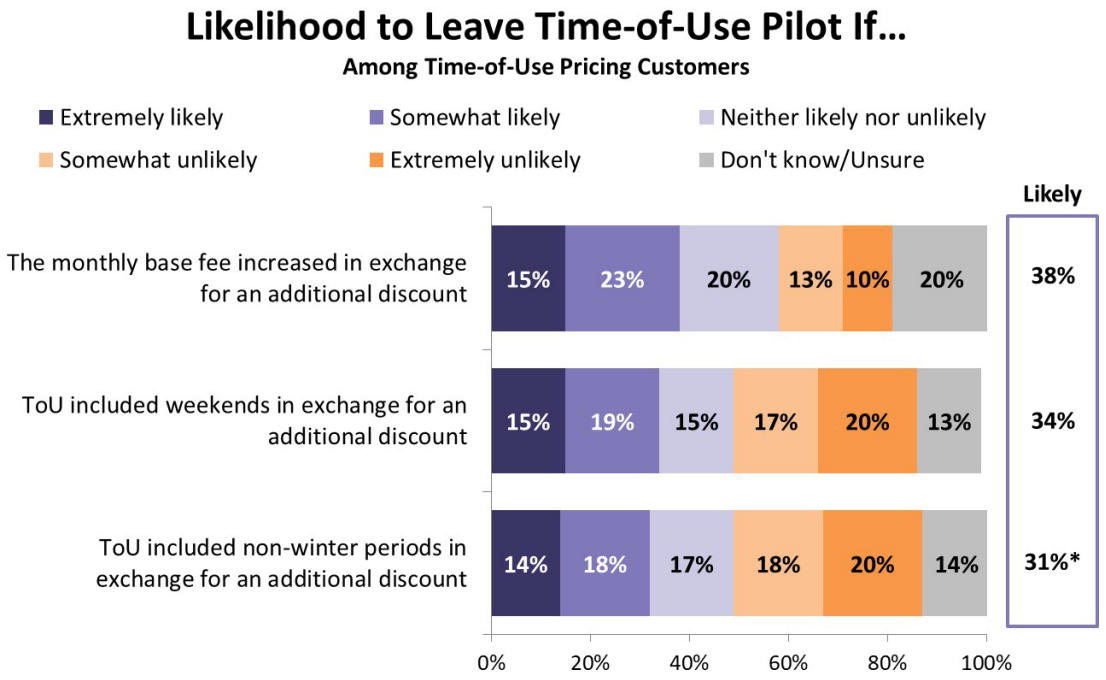


Q.11Fa-c: **[IF TIME-OF-USE PRICING CUSTOMER]** Nova Scotia Power is considering modifications to the Time-of-Use rate plan and would like your opinion of a few different options under consideration. The winter season for each option is between November 1 – March 31, like your current plan. How important or unimportant is it to you that… (n=1,332) *New questions in 2025.*

Likelihood to Leave Time-of-Use Pilot

One in three ToU participants would be at least somewhat likely to leave the ToU pilot should any changes occur, regardless of additional incentives offered.

To gauge participant likelihood to leave the program if certain changes made, three scenarios were presented. Overall, one in three each indicate they would leave the pilot if ***the monthly base fee increased in exchange for an additional discount*** (38%), if ***ToU included weekends in exchange for an additional discount*** (34%), or if ***ToU included non-winter periods in exchange for an additional discount*** (31%). Results signal that many participants are hesitant to changes, regardless of the additional discount being offered. (Tables 11Ea-c)

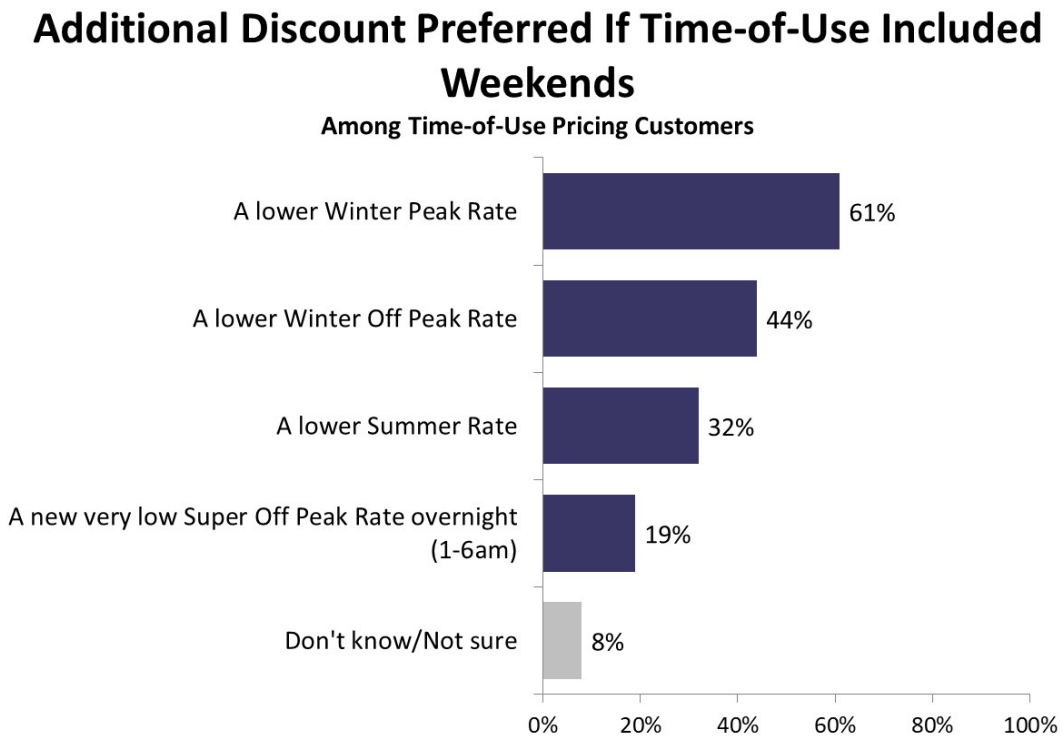


Q.11Ea-c: **[IF TIME-OF-USE PRICING CUSTOMER]** How likely would you be to leave the Time-of-Use pilot if… (n=1,332) *New questions in 2025. *Due to rounding.*

Preferred Discount if Time-of-Use Included Weekends

If ToU began including weekends, participants would prefer a lower winter peak and off-peak rate.

When asked what kind of additional discount would be preferred if ToU included weekends, a majority of participants would prefer a lower winter peak rate. More than four in ten chose a lower winter off peak rate and the less popular choices included a lower summer rate or a new very low Super off peak rate overnight. Results indicate ToU participants would prefer additional discounts to a winter rate than any other options. (Table 11g)



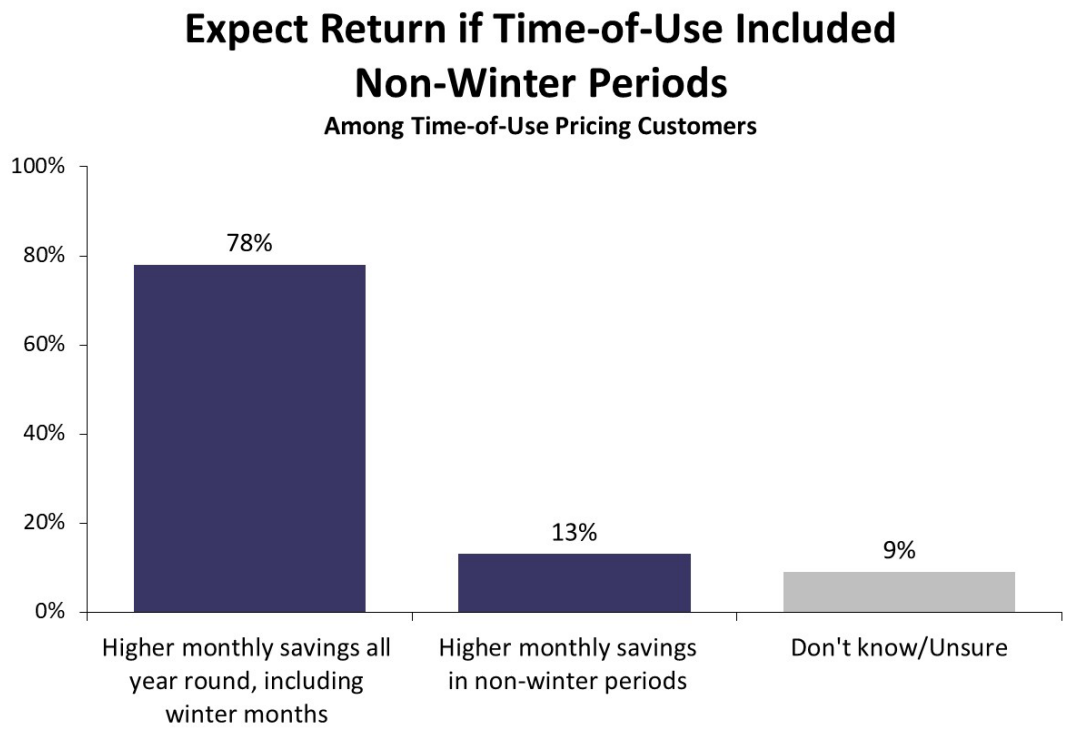
Q.11g: **[IF TIME-OF-USE PRICING CUSTOMER]** If Time-of-Use included weekends in exchange for an additional discount on energy usage, which would you most prefer? Select up to three. (n=1,332) *New question in 2025.*

Expected Return if Time-of-Use Includes Non-Winter Periods

ToU participants would expect higher year-round savings if ToU included non-winter periods.

ToU participants would largely expect higher monthly savings all year round, including winter months, if ToU was extended to include non-winter periods. About one in ten would expect higher monthly savings in non-winter periods or are unsure.

Results did not signal any significant differences in responses based on heat source or household income. (Table 11h)

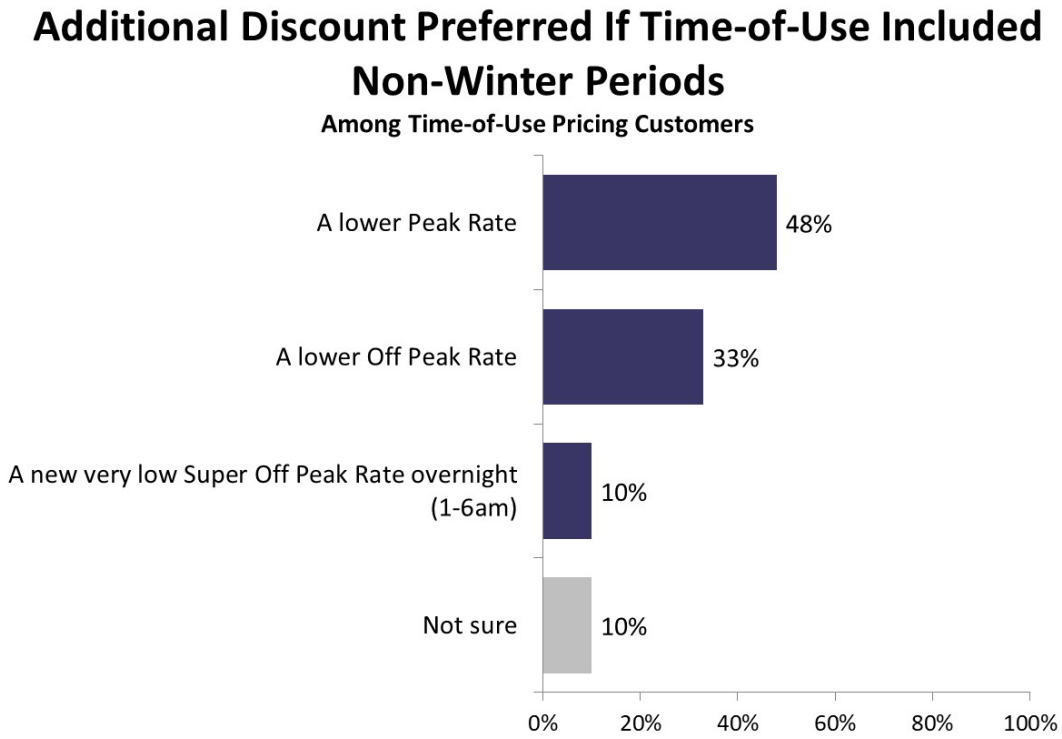


Q.11h: **[IF TIME-OF-USE PRICING CUSTOMER]** If Time-of-Use was extended to include non-winter periods what would you expect in return? (n=1,332) *New question in 2025.*

Preferred Discount if Time-of-Use Includes Non-Winter Periods

While preferences are somewhat mixed, half of participants would prefer a lower peak rate than a lower off peak rate.

When asked to indicate a discount preference should ToU included non-winter periods, nearly one-half of participants select a lower peak rate, followed by one-third who would prefer a lower off-peak rate. Just one in ten would like a new very low off-peak rate overnight. (Table 11i)

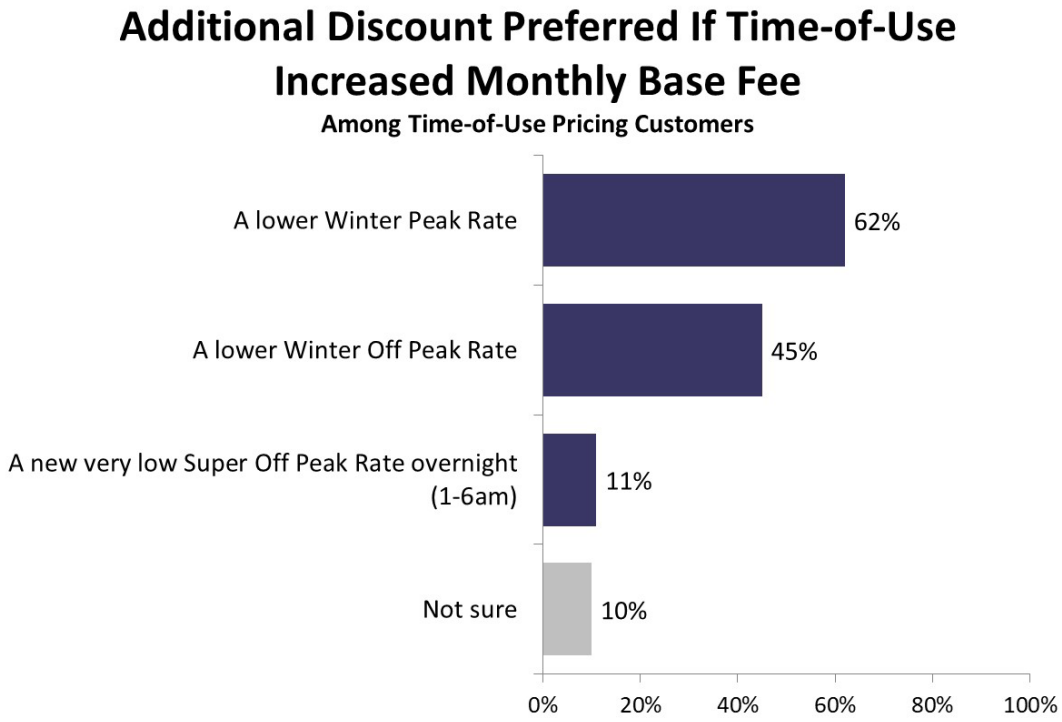


Q.11i: **[IF TIME-OF-USE PRICING CUSTOMER]** If Time-of-Use included non-winter periods in exchange for an additional discount on energy usage, which would you most prefer? (n=1,332) *New question in 2025.*

Discounted Electricity Costs Preferred If Monthly Fee Increased

Again, discounts to winter peak rates are the clear preference, this time in response to an increase to the monthly base fee.

When asked to indicate a discount preference should the pilot's monthly base fee increase, the majority would prefer a lower winter peak rate, followed by near half who prefer a lower winter off peak rate. Very few show interest in a new very low Super off peak rate overnight. (Table 12)



Q.12: **[IF TIME-OF-USE PRICING CUSTOMER]** If the program were to increase the monthly base fee in exchange for significant discounted electricity costs, which of the following changes would you most prefer? Select up to two. (n=1,332)
New question in 2025.

Pricing Plan Preferences: Motivations



Recent Joiners Main Reason For Choosing Plan

Saving money dominates as the main reason for participating in a rate plan, distantly followed by non-monetary motivations.

New participants were asked why they chose to join ToU or CPP. As expected, the primary reason for joining was to ***save money***, followed by very few who cited any other motivation. No more than 9% of participants mentioned any non-monetary rationale. (Table 20)

*"**To keep our bill low as low as it can go.** Price of living has skyrocketed and we thought this was created to help people. But we may have been wrong who knows." – CPP Year 4 Participant*

*"I was looking for ways to **decrease my overall electric costs**. The lower rates during off peak hours may be helpful. My highest cost is heating and as two seniors living in the home any help is welcomed. Also I think less strain on the grid will be more efficient for the community especially for young families." – CPP Year 4 Participant*

*"**To see how much money I can save on power yearly.** I am retired and on a fixed income and need to save living expenses wherever possible." – ToU Year 4 Participant*

*"I use electricity in the summer due to electric air conditioners, so I am **trying to reduce the cost of my electricity in the summer months primarily**." – ToU Year 4 Participant*

Main Reason for Participating in Rate Plan

Key Unaided Mentions Among New Participants

	Time-of-Use				Critical Peak			
	2022 (n=428)	2023 (n=137)	2024 (n=343)	**2025 (n=314)**	2022 (n=174)	2023 (n=58)	2024 (n=157)	**2025 (n=186)**
Save money	87%	82%	84%	**89%**	86%	86%	81%	**91%**
Save the planet/More 'green'/ Energy efficient	15%	17%	10%	**9%**	13%	16%	8%	**4%**
Change my habits/More awareness	17%	26%	19%	**5%**	19%	28%	22%	**6%**
Fits well with my schedule/lifestyle/ habits already	n/a	n/a	8%	**5%**	n/a	n/a	6%	**1%**
Curiosity/Wanted to try it out	4%	3%	4%	**3%**	3%	3%	7%	**2%**
Help NSP power management/As recommended by NSP	2%	1%	2%	**2%**	4%	5%	8%	**8%**

Q.20: **[AMONG YEAR 2 PARTICIPANTS ONLY IN 2023/YEAR 3 PARTICIPANTS ONLY IN 2024/YEAR 4 PARTICIPANTS ONLY IN 2025]** What is the main reason you wanted to participate in the [Time-of-Use/Critical Peak] rate plan? **Skip added in 2023/2024/2025. In 2024 and 2025 this table includes 500 randomly coded responses.*

Previous Joiners Main Reason For Continued Pilot Participation

The primary reason for remaining on TVP pilots is also to save money, although fewer indicate this as a motivating factor than those in their first year of the pilot.

Year 1, 2, and 3 participants continue to participate in their respective rate plans ***to save money.*** In 2025, fewer participants in both pilots say the rate plan is ***easy to plan around*** (down 13 points among ToU; down 10 points among CPP). These findings suggest that participants may be finding it harder to plan around the peak periods. (Table 20a)

"I wanted to better understand how I could reduce my power bill by shifting my energy use. ***The pilot gave me a chance to experiment and potentially save money.****" – CPP Year 2 Participant*

"I am retired and can shift my consumption to match the pilot hours. It saves me $$. *I am a senior in a fixed income and every drop of savings helps my situation." – CPP Year 3 Participant*

"I think I am saving on energy costs annually. *I am careful with peak hours during the winter months and have a need for more than average energy use in the summer months (air conditioning and woodworking shop machines)." – ToU Year 3 Participant*

"I mostly try to do things in off peak times*, weekends and holidays during winter months, so makes sense to use it for the break in the summer." – ToU Year 3 Participant*

Main Reason for Continuing to Participate in Rate Plan

Key Unaided Mentions
Among Year 1, 2, and 3 Participants

	Time-of-Use			Critical Peak		
	2023 (n=308)	2024 (n=322)	**2025 (n=330)**	2023 (n=120)	2024 (n=144)	**2025 (n=170)**
To save money/off-peak rates	60%	70%	**70%**	75%	76%	**79%**
Easy to plan around peak/off-peak times	12%	27%	**14%**	8%	19%	**9%**
To be more energy efficient/fight climate change	8%	7%	**8%**	11%	10%	**9%**
Access to energy usage details/More conscious of energy use/Encourages energy saving habits	6%	7%	**8%**	10%	6%	**6%**

Q.20a: **[AMONG YEAR 1 PARTCIPANTS IN 2023/YEAR 1 AND 2 PARTICIPANTS IN 2024/YEAR 1, 2, AND 3 PARTICIPANTS IN 2025]** What is your reason for continuing to participate in the [Time-of-Use/Critical Peak] plan? *New question in 2023. In 2025 this table includes 500 randomly coded responses.*

Reason for Choosing Plan *(continued)*

While reasons for choosing their respective program remain similar, a decreasing number of CPP participants say the pilot fits their lifestyle.

The top reasons why ToU participants chose their current pilot as opposed to the CPP is because it *fits my lifestyle/schedule,* is *easier to control/manage,* and to *save money/better rates*. These reasons fall in line with previous years.

CPP participants most often mention they chose the pilot because it is *easier to control,* while a decreasing number who cite that it *fits my lifestyle/schedule.* Another quarter say they chose CPP to *save money*. (Table 21)

> *"While I feel the Critical Peak Pricing is overpriced, for our household,* ***it was the least painful and aligned more with our lifestyle.****" – CPP Year 4 Participant*

> *"The peak event only occur during the winter, and I get a lower rate at all other times.* ***I can shift heavy power use out of the critical times, but I only need to do that occasionally instead of every day****." – CPP Year 1 Participant*

> *"Seems to be a better deal,* ***without the risk of the really high rate at an inconvenient time****." – ToU Year 3 Participant*

> *"It seemed like the better option for us as* ***we travel during the winter****."– ToU Year 4 Participant*

Main Reason for Participating in Current Plan Opposed to Alternative Rate Plan

Key Unaided Mentions

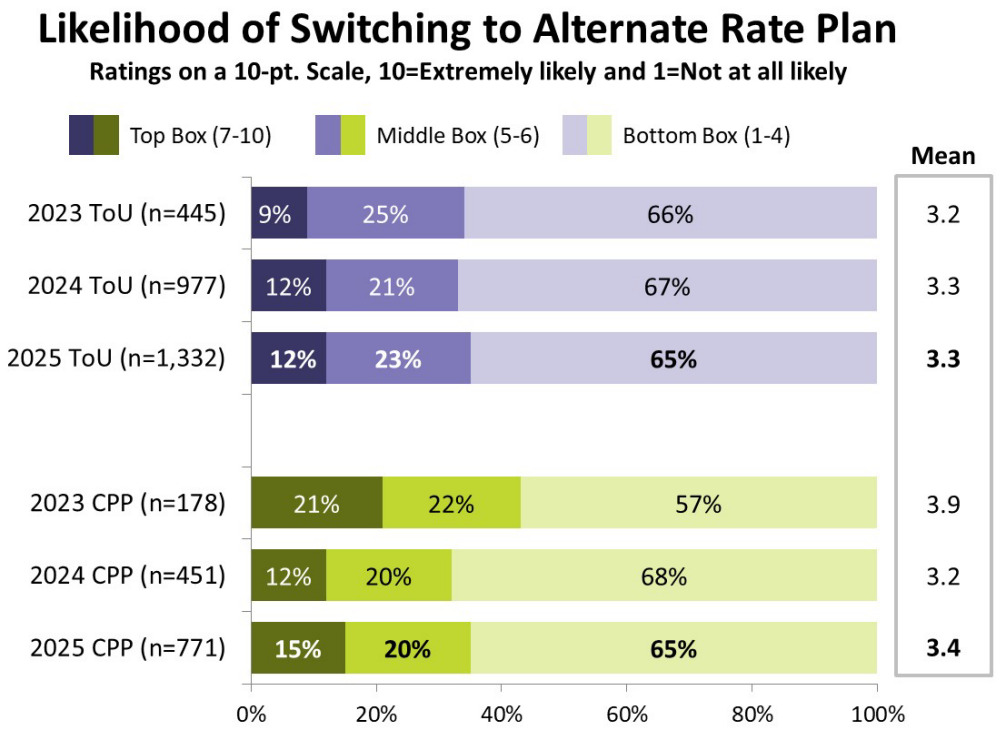
	Time-of-Use				Critical Peak			
	2022 (n=428)	2023 (n=445)	2024 (n=346)	**2025 (n=318)**	2022 (n=174)	2023 (n=178)	**2024 (n=154)**	**2025 (n=182)**
Fits my lifestyle/schedule	32%	28%	25%	**24%**	25%	30%	40%	**27%**
Easier to control/manage	13%	24%	27%	**23%**	16%	29%	34%	**30%**
Save money/better rates	16%	24%	21%	**23%**	25%	26%	25%	**25%**
Consistent/Predictable	9%	11%	12%	**6%**	3%	6%	2%	**1%**
Easier to understand	8%	6%	8%	**6%**	4%	3%	5%	**3%**
No other option offered/Not aware of other plans	7%	16%	6%	**10%**	4%	10%	6%	**7%**
Don't know/Not sure	10%	7%	10%	**11%**	10%	7%	4%	**8%**

Q.21: What is the main reason you chose the [Time-of-Use/Critical Peak] rate as opposed to the [Critical Peak/Time-of-Use] rate plan? *In 2024 and 2025 this table includes 500 randomly coded responses.*

Likelihood of Switching to Alternate Plan

Fewer than one in five participants would consider switching to an alternate TVP pilot.

A similar proportion of participants from both rate plans express a likelihood to consider switching to the other offered pilot. That said, an identical number of participants from ToU and CPP (65%) each indicate they would not be likely to switch pilots. The limited interest suggests that unsatisfied participants would be more likely leave the TVP pilot than switch rate plans. (Table 21a)



Q.21a: How likely are you to consider switching from your current plan [Time-of-Use/Critical Peak] to the [Critical Peak/ Time-of-Use] plan? *New question in 2023.*

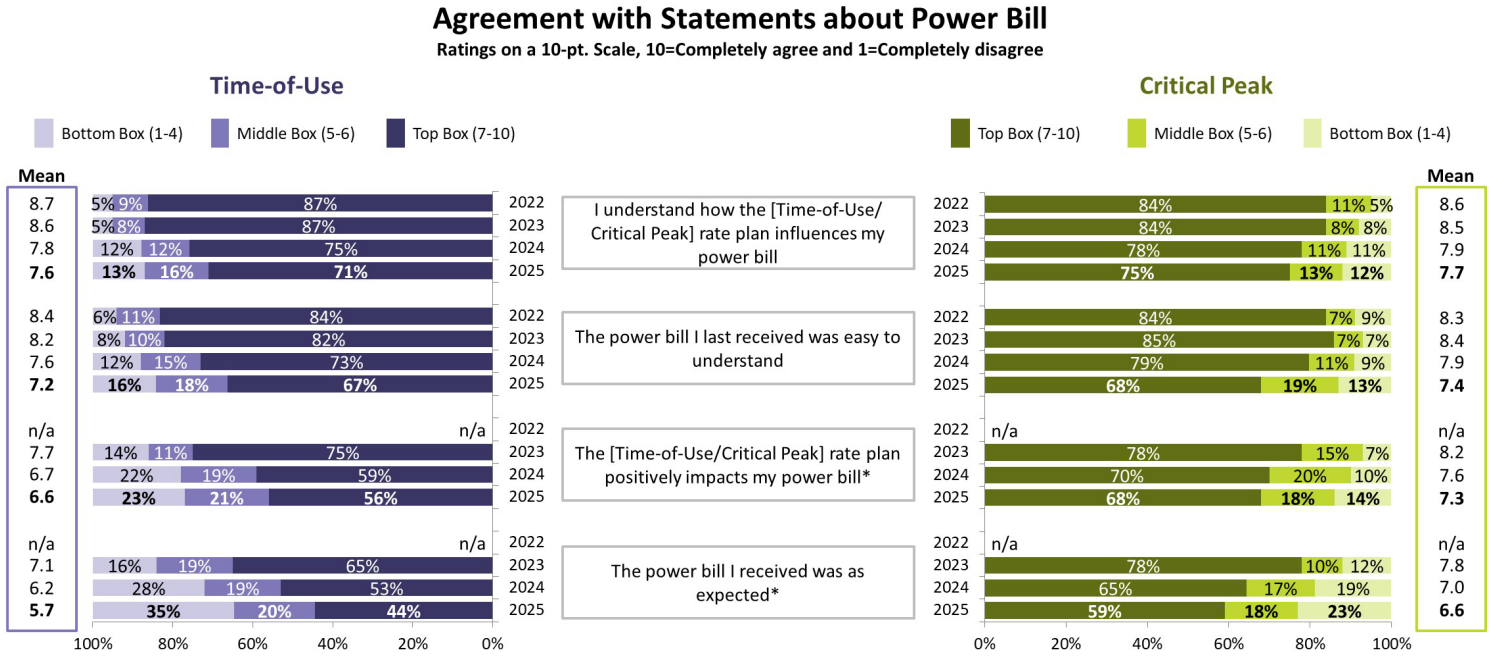
Billing



Billing

CPP and ToU participants are increasingly struggling to understand their bills and the impact of their participation in pilot programs.

Findings show a continued downward trend across all statements related to bills for both ToU and CPP participants. Although still a majority, significantly fewer CPP participants agree that the last power bill they received was ***easy to understand*** (68%, down 11 points), and ToU participant agreement dropped numerically (67%; down 6 points). In 2025, fewer than one-half of ToU participants now agree the power bill they received ***was as expected*** (44%, down 9 points). Interestingly, year 4 CPP participants more commonly agree that their power bill was as expected, and their rate plan positively impacts their bill compared to year 4 participants in the ToU rate plan. Similar to years past, newer TVP rate plan participants tend to bring down the overall scores because they have yet to experience a full year on the plan. (Tables 15a,c-e)



Q.15a, c-e: Overall, to what extent do you agree or disagree with each of the following statements. (Time-of-Use – 2022: n=428; 2023: n=445; 2024: n=977; 2025 n=1,332. Critical Peak – 2022: n=174; 2023: n=178; 2024: n=451; 2025: n=771) **New questions in 2023.*

Additional Comments on Billing

Participants are attentive to their bills, noting higher-than-normal prices, requesting savings comparisons, more details, or more time to review the data.

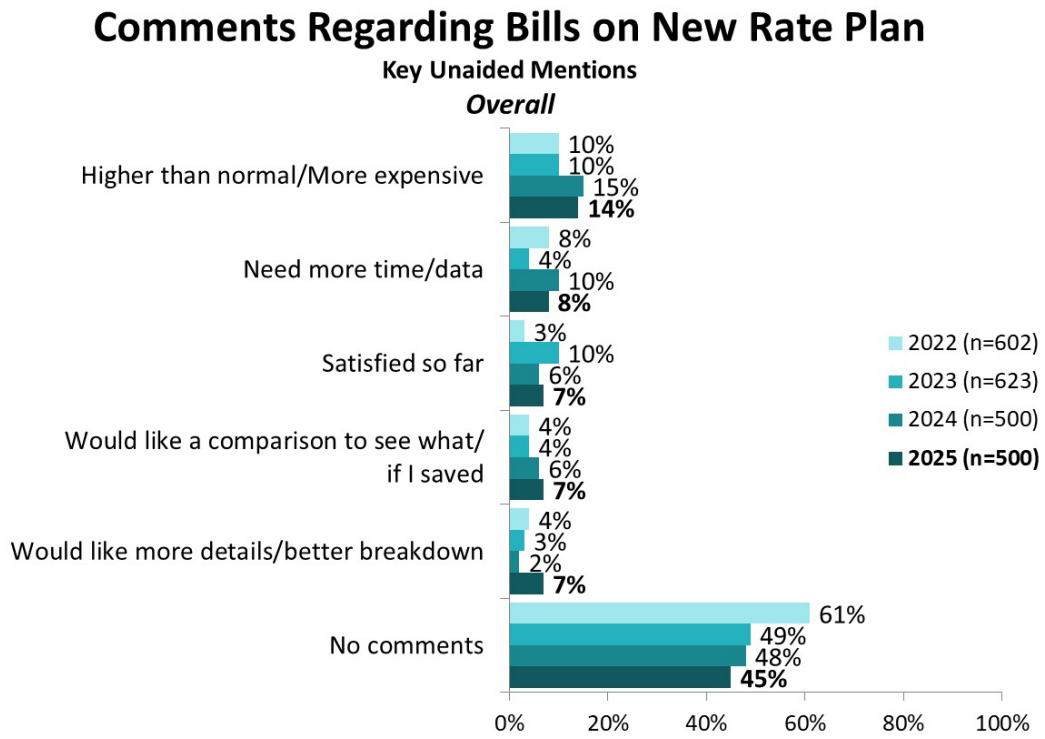
Fewer than one-half of participants have any comments to offer regarding bills on the new rate plan (45%). Those who do have thoughts mention their bills were higher than normal, they need more time and data, want a comparison to see savings, or want more details. Few simply state they are satisfied so far. CPP participants are less likely than ToU participants to offer any commentary. (Table 16)

> *"**I am not sure if I received better rate.** It would be helpful if you indicated on the bill what it would have been if I did not use critical peak." – CPP Year 4 Participant*

> *"**I do have a hard time actually understanding my recent bills**. I don't see that it has affected my over all billing costs and I don't see anything on there that tells me exactly how much I've been saving." – ToU Year 4 Participant*

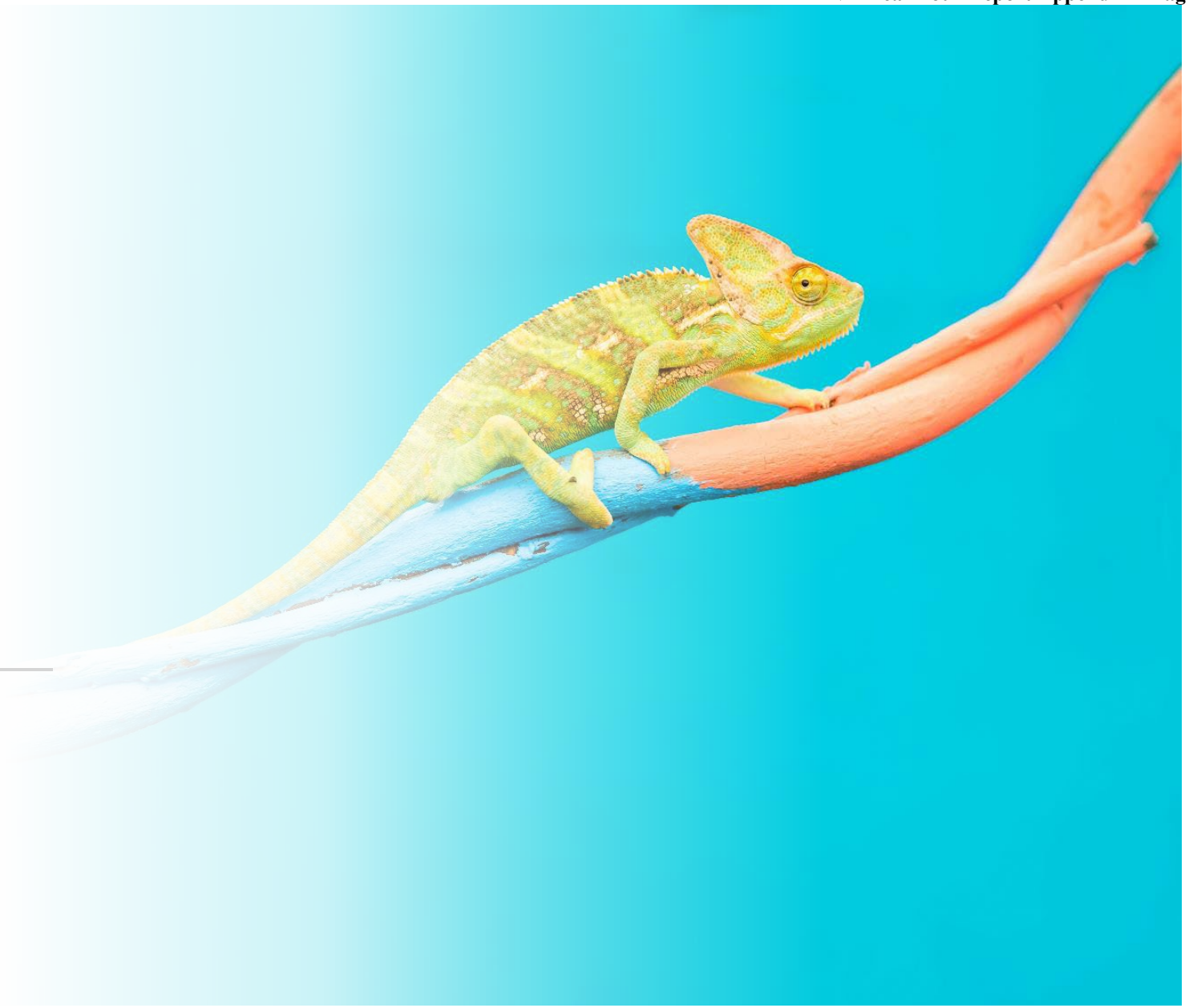
> *"**A better breakdown of the power used during a peak would be appreciated.** Also seeing those statistics in my energy usage and a breakdown there would be great in order to cut further costs." – ToU Year 4 Participant*

> *"**Getting a bill with 4 different power rates on it was troublesome to understand**. There was no explanation for it which is why i had to contact NS Power." – ToU Year 4 Participant*



Q.16: Please share any comments you have regarding your bills so far on the new rate plan. *In 2024 and 2025 this table includes 500 randomly coded responses.*

Changing Behaviours

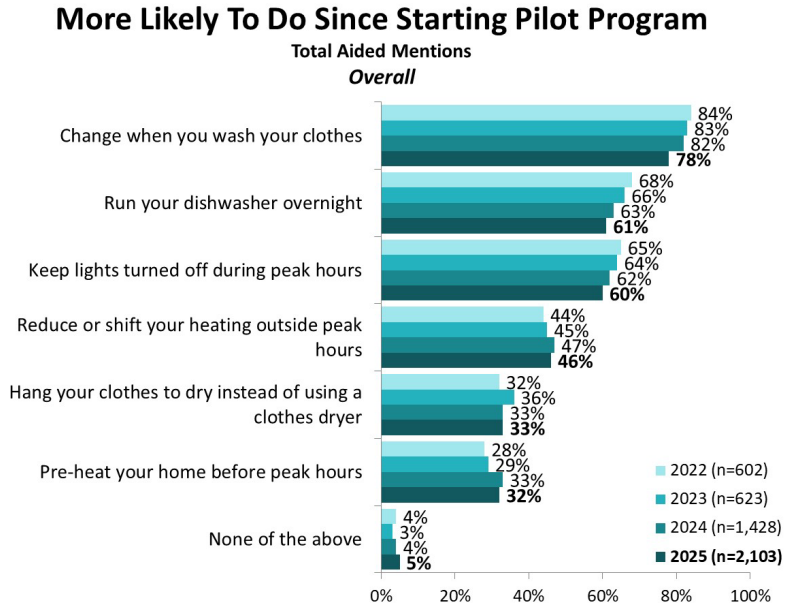


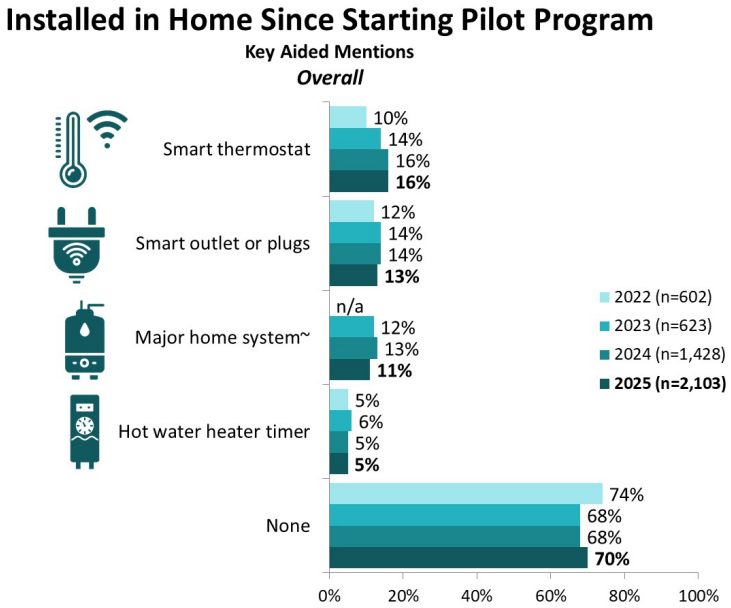
Energy Saving Behaviours

It is clear that program participation influences participant behaviours.

Mostly consistent year-over-year, participants state they are likely to ***change when they wash their clothes, run their dishwasher,*** and ***keep lights turned off.*** Fewer than half of participants will ***reduce or shift their heating outside peak hours, hang their clothes, or pre-heat their home***. Very few state they do none of the given activities (5%). Between the pilots, ToU participants are more likely to change when they wash their clothes and run their dishwasher overnight, while CPP participants will more often keep lights off, reduce/shift heating, or pre-heat their homes, all since starting in their respective pilots. (Table 22Ra)

Since the pilot began, only three in ten participants have installed any energy-efficient or smart technology. Smart thermostats were the most installed, while hot water heater timers were rarer. It is important to note that installing a smart product may not be caused by participation in the pilot. (Table 22Rb)





Q.22Ra: Since starting on this pilot program, have you been more likely to do any of the following. Select all that apply. | Q.22Rb: Since starting on this pilot program, have you installed any of the following in your home? *~New option in 2023.*

Other Changes to Electricity Usage

Three-quarters of participants state they have, in some way, changed their electricity use after joining the pilot program.

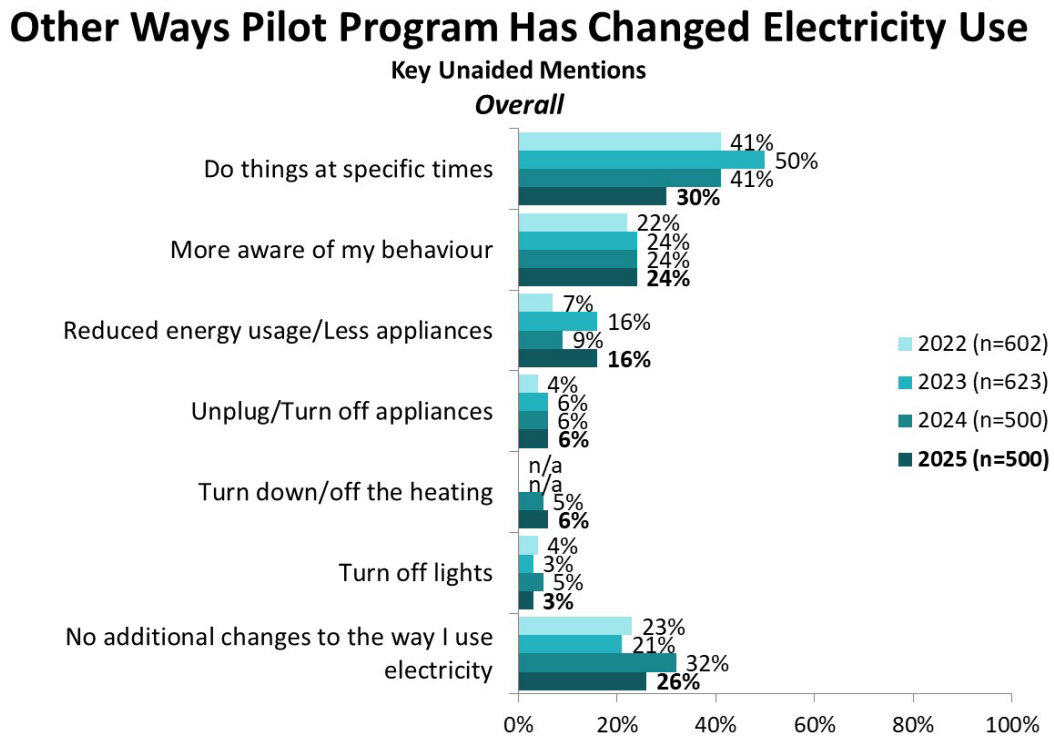
This year, fewer participants state they *do things at specific times* (30%; down 11 points), while marginally more cite they have *reduced energy usage* (16%; up 7 points). All other energy use actions are mostly consistent year-over-year. (Table 24)

> *"During the November-March off-peak period,* ***I move all the high-consumption household tasks to the weekends: laundry (washer and dryer), dishwasher, baking, vacuuming, etc.****" – ToU Year 1 Participant*

> ***"The dishwasher and laundry are done at the nonpeak times, I bake on the weekends, I plan my meals to be over by 5:00 pm, I use my air fryer more rather than the big oven."*** *– ToU Year 4 Participant*

> *"****We manually turn off appliances like our hot water heater for peak periods.*** *We do not charge the electric car during peak periods."* *– CPP Year 2 Participant*

> *"****It's made me more aware of how to conserve energy and to lessen the strain on power grids.*** *I hope to follow the same power usage pattern as the pilot program when ever possible." – ToU Year 4Participant*



Q.24: In what other ways, if at all, has the pilot program changed the way you use electricity? *In 2024 and 2025 this table includes 500 randomly coded responses.*

Usage



Home Heating

Based on the past four years, TVP participants generally do not drastically alter their home's typical room temperature during the winter months.

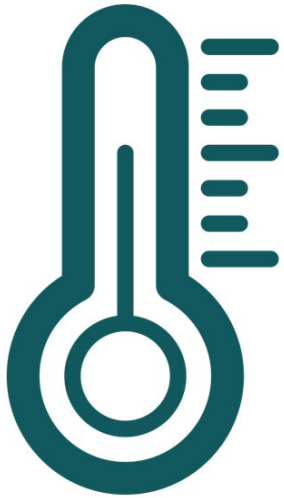
ToU and CPP participants who use electric heat as at least one of their heat sources are primarily keeping their typical room temperature between 19 and 22 degrees, in line with results from last year.

Seven in ten of the same group report they reduce the temperature when they are not at home or during the night, again, consistent with 2024.

After four years of tracking, it seems as though participating in the TVP pilot programs does not have a big impact on the temperature at which participants keep their home. (Tables 28 and 29)

Home's Typical Room Temperature During Winter Months

Among Electric Heat Customers
Overall



8% Above 22 degrees Celsius (71.5 Fahrenheit) *(vs. 6% in 2022, 9% in 2023, and 8% in 2024)*

68% Between 19 and 22 degrees Celsius (66 and 71.5 Fahrenheit) *(vs. 75% in 2022, 70% in 2023, and 70% in 2024)*

24% Below 19 degrees Celsius (66 Fahrenheit) *(vs. 18% in 2022, 21% in 2023, and 21% in 2024)*

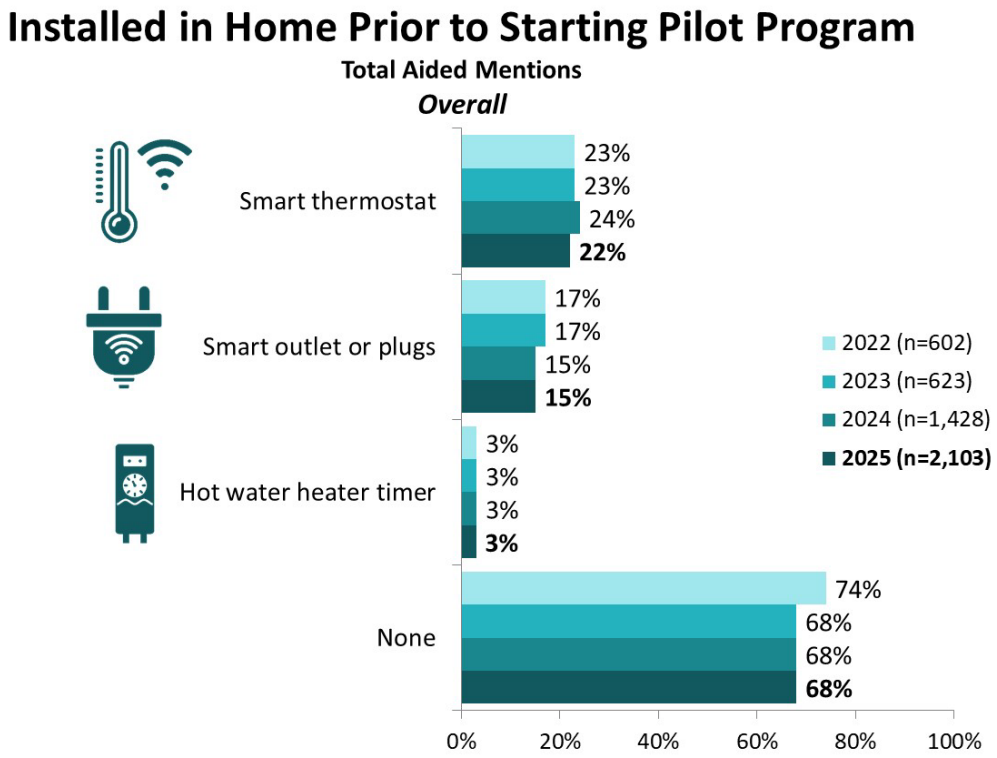


[IF ELECTRIC HEAT CUSTOMERS] Q.28: Which of the following best describes your home's typical room temperature in the winter months? | Q.29: Do you reduce the temperature in your home when you're not at home or at night time? (2022: n=416; 2023: n=488; 2024: n=1,155; 2025: n=1,689) *In 2024 and 2025, sample size differs due to an upcoding in Q.21.*

Energy Efficient Products

Participants commonly did not have energy-efficient technology installed in their homes prior to joining the program.

Reports of having smart devices installed before starting the pilot program are relatively unchanged from 2024. Two in ten participants had a smart thermostat already, followed by fewer who had smart outlets or hot water heater timers. Two-thirds did not have any before starting in the pilot program. (Table 30R)



Q.30R: Prior to starting this pilot program, did you have any of the following already installed in your home?

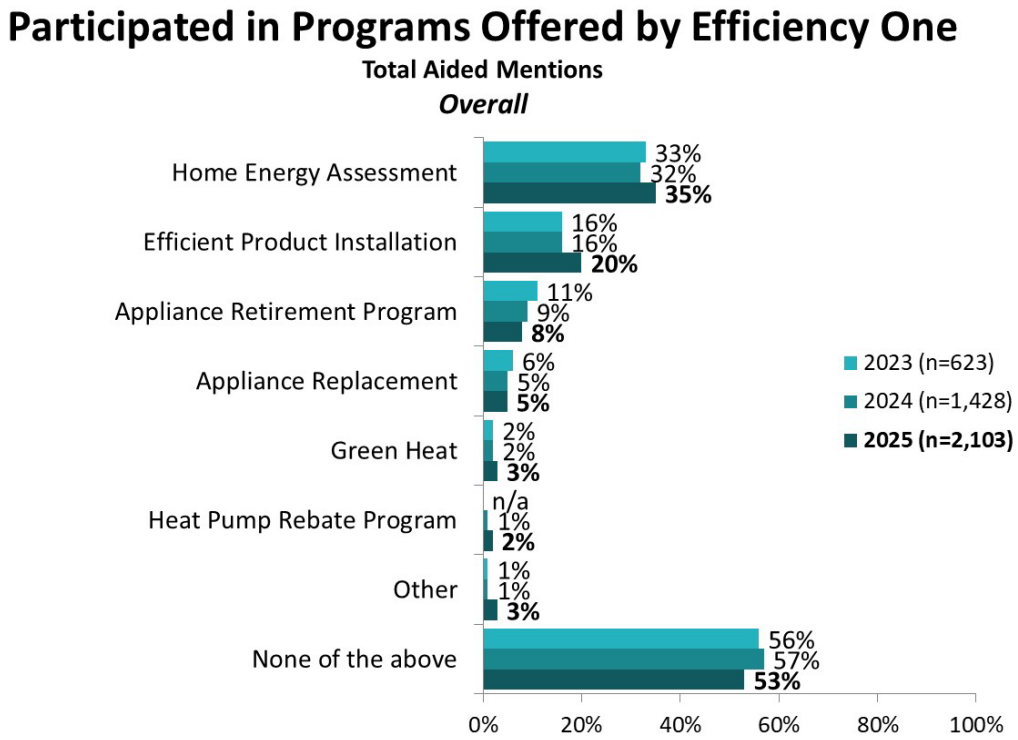
Efficiency One Programs

Participation in Efficiency One programs remains only moderate.

In 2025, the wording was adjusted to reframe the question to capture any previous participation in any of the Efficiency One program versus current participation.

Despite the change in question wording, fewer than one-half of participants mention they have participated in any of the programs offered by Efficiency One. The most popular program remains the Home Energy Assessment, while few participate in Green Heat or Heat Pump Rebate Program.

Following this wording change, results are consistent with previous years, perhaps suggesting that TVP participants are indeed less likely to engage with E1 programs. (Table 30Sa)



Q.30Sa: Have you participated in any Efficiency One programs (such as heat pump rebates, water heater timer, smart thermostat)? *New question in 2023. Slight change in question wording in 2024 and 2025.*

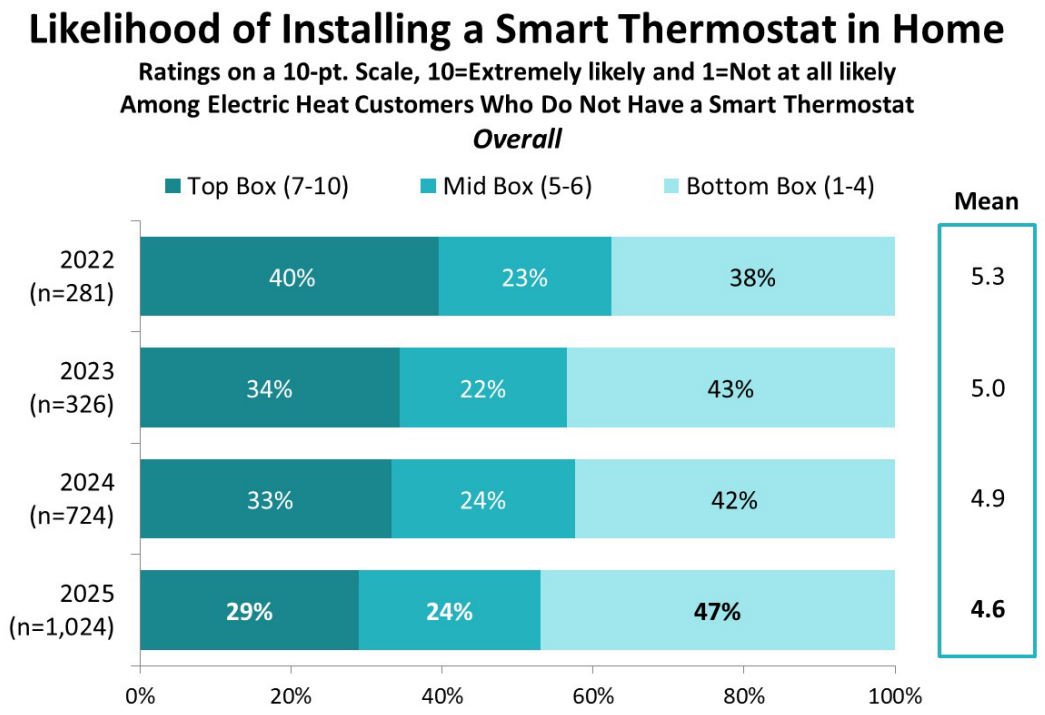
Likelihood of Installing a Smart Thermostat

There is a mixed likelihood of installing a smart thermostat after joining a Time-Varying Pricing Rate pilot program.

Reports of participants being likely to install a smart thermostat continue to slowly decline, with the current proportion of those unlikely to install one now at its highest level since tracking began (47%). This presents an opportunity to further promote the benefits of smart thermostats to TVP electric heat participants.

While not explored in this research, it is possible that the decrease in interest could be related to the challenges of installation (e.g., cost of installation, purchase), that those interested in getting a smart thermostat have already done so, or it could signal a growing skepticism of smart thermostats. (Table 31)

Smart thermostats work by helping to set heating schedules (e.g., raise temperature while at [work/home] and lower temperature while you are away), allow you to control the thermostat using your smart phone, among other features.



Q.31: **[IF ELECTRIC HEAT CUSTOMERS AND DO NOT HAVE A SMART THERMOSTAT IN Q.27 OR Q.22RB OR Q.30R]** Now that you're on a Time-Varying Pricing Rate Pilot, how likely would you say you are to install a smart thermostat?

Reason for Installing Smart Thermostat

Cost savings is the primary reasonsthat participants installed or are interested in installing a smart thermostat.

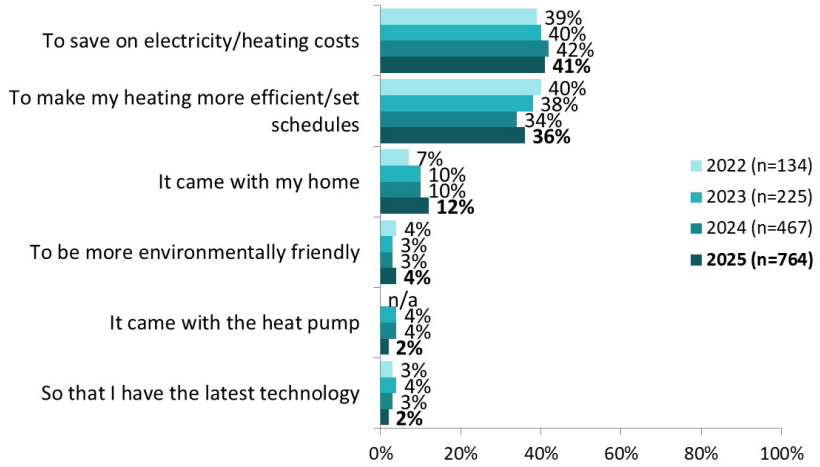
The top reasons given by participants who currently have a smart thermostat installed are to save on electricity or heating costs and to improve heating efficiency. Results are virtually unchanged from recent years. (Table 32)

Seven in ten (71%; down 4 points) who are likely to install a smart thermostat say it would be to save on electricity/heating costs, in line with previous findings. (Table 33)

Primary Reason for Having Installed a Smart Thermostat

Key Aided Mentions Among Electric Heat Customers Who Have a Smart Thermostat

Overall

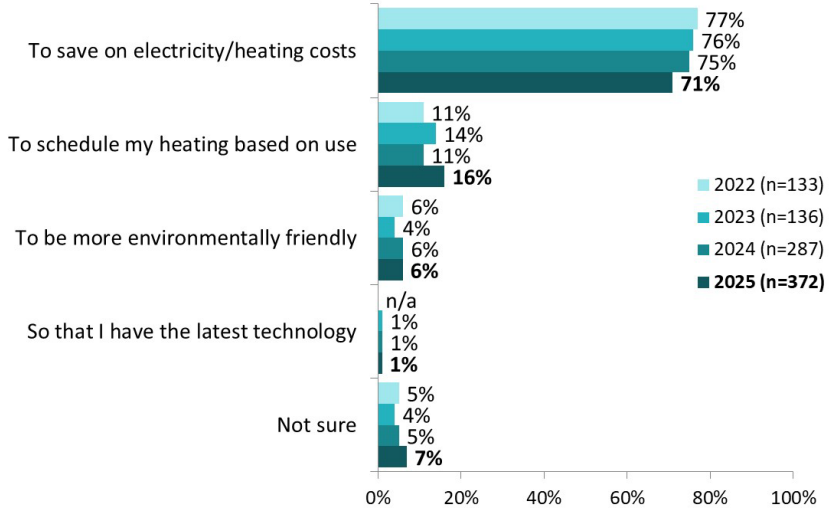


Q.32: **[IF ELECTRIC HEAT CUSTOMERS AND HAVE A SMART THERMOSTAT IN Q.27 OR Q.22RB OR Q.30R]** Thinking about the smart thermostat that you have installed, please select the single most important reason as to why you installed it. *In 2023, sample size differs slightly from Q.26 due an upcoding in Q.26. In 2025, sample size differs slightly from Q.27 due to an upcoding by 3.*

Primary Reason for Interest in Installing Smart Thermostat

Total Aided Mentions Among Electric Heat Customers Who Rated Likelihood of Installing 6-10

Overall



Q.33: **[IF ELECTRIC HEAT CUSTOMERS AND RATINGS OF 6-10 IN Q.31]** What is the single most important reason why you are interested in installing a smart thermostat?

Final Thoughts



Final Feedback

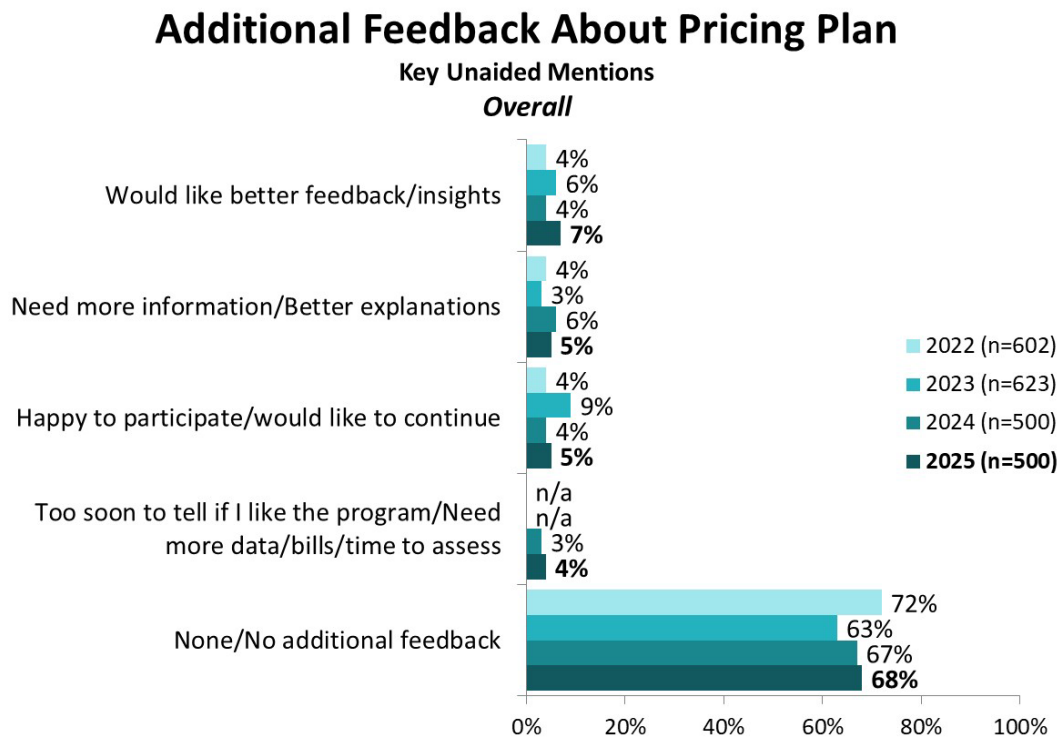
Few participants provide additional commentary regarding their respective rate plans.

Two-thirds of participants did not offer any additional feedback about the pricing plan. Those who gave comments primarily suggest better feedback and explanations, are happy to be in the program or still need more time to decide. (Table 25)

> *"**Two critical peak pricing events within 24 hours is not reasonable** and very difficult for us to accommodate.– CPP Year 4 Participant*

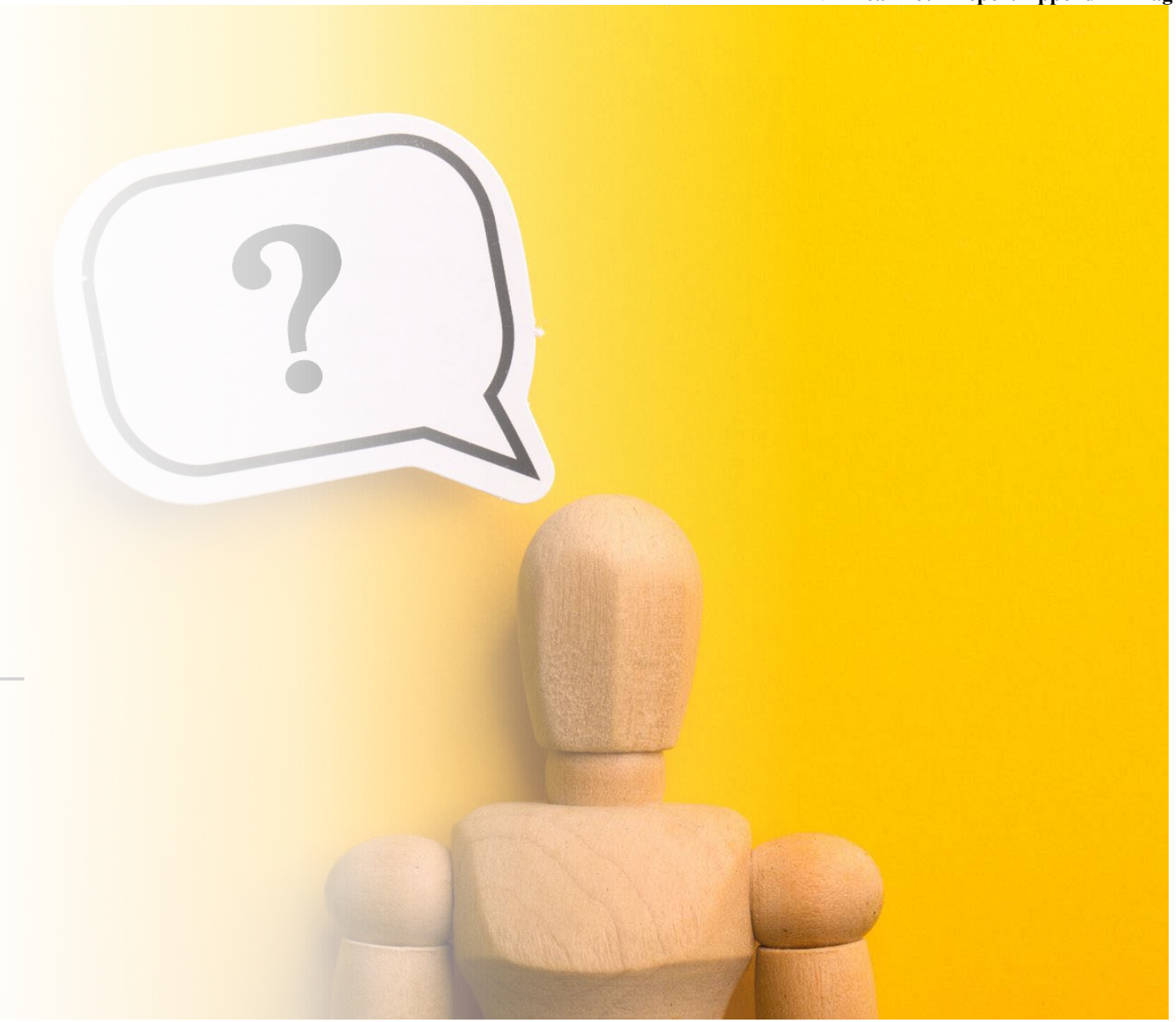
> *"**I'd like to receive info via email about what I saved over this program per year** and not have to try and calculate it from my power bill." – CPP Year 1 Participant*

> *"We used less energy which was great. **Tracking energy usage was enjoyable**. Unfortunately, **the cost off our energy bill remained the same from the same period last year**." – ToU Year 4 Participant*



Q.25: Is there any other feedback you would like to provide Nova Scotia Power about the [Time-of-Use/Critical Peak] rate plan? *In 2024 and 2025 this table includes 500 randomly coded responses.*

Respondent Profiles



Respondent Profile: Time-of-Use

2025 Respondent Profile: Time-of-Use Customers *(n=1,332)*

69% Have used *MyEnergy Insights*

Primary Heating Energy Source

- 67% Electricity
- 19% Oil
- 6% Wood
- 3% Natural gas
- 3% Propane

Temperature Control of Main Heating System

Among Electric Heat Customers (Primary/Secondary)

- 45% Regular thermostat(s) with temperature settings
- 25% Clock or programmable thermostats
- 22% Smart thermostat that you can control from a wireless device
- 6% Simple on/off switch or no temperature control
- 4% Dial control without temperature settings
- 2% Remote control/ Remote for heat pump

<1% Other 4% Not sure

Use in Primary Residence

- 2% A pool (heated in summer)
- 5% A hot tub or jacuzzi
- 18% Plug in electric heater
- 61% Stand-alone freezer
- 12% Centrally ducted AC
- 16% A window or plug in AC
- 86% Electric clothes dryer
- 6% An electric vehicle
- 45% Ceiling/ window fans
- 42% A dehumidifier
- 3% None of the above

Age of Home

L.T. 1 year	1%
1-10 years	13%
11-20 years	12%
21-30 years	12%
31-40 years	14%
41-50 years	13%
50+ years	28%
Not sure	7%

44.5 years *Average age of home*

of People in Household

1	23%
2	47%
3+	26%

2.3 Average

of People Home During...

	Daytime	Evening	Weekend
0	12%	0%	0%
1	40%	23%	24%
2	38%	46%	46%
3+	4%	24%	24%

Education

74% Have *graduated* college or university

- 1% Less than high school
- 9% Graduated high school
- 11% Some college/university
- 1% Other
- 5% Prefer not to answer

Household Income

Under $50,000	18%
$50,000-$99,999	32%
$100,000 +	27%
Prefer not to answer	22%

Gender

55% Woman 39% Man

<1% Non-binary

6% Prefer not to answer

Respondent Profile: Critical Peak Pricing

2025 Respondent Profile: Critical Peak Pricing Customers *(n=771)*

72% Have used *MyEnergy Insights*

Primary Heating Energy Source

- 71% Electricity
- 16% Oil
- 5% Wood
- 3% Natural gas
- 3% Propane

Temperature Control of Main Heating System

Among Electric Heat Customers (Primary/Secondary)

- 40% Regular thermostat(s) with temperature settings
- 26% Clock or programmable thermostats
- 26% Smart thermostat that you can control from a wireless device
- 5% Dial control without temperature settings
- 4% Simple on/off switch or no temperature control
- 3% Remote control/ Remote for heat pump

<1% Other 3% Not sure

Use in Primary Residence

- 3% A pool (heated in summer)
- 6% A hot tub or jacuzzi
- 20% Plug in electric heater
- 63% Stand-alone freezer
- 14% Centrally ducted AC
- 84% Electric clothes dryer
- 8% An electric vehicle
- 15% A window or plug in AC
- 40% Ceiling/ window fans
- 43% A dehumidifier
- 3% None of the above

Age of Home

L.T. 1 year	0%
1-10 years	12%
11-20 years	10%
21-30 years	13%
31-40 years	17%
41-50 years	12%
50+ years	30%
Not sure	6%

47.5 years *Average age of home*

of People in Household

1	22%
2	48%
3+	26%

2.3 Average

of People Home During...

	Daytime	Evening	Weekend
0	12%	0%	0%
1	40%	22%	22%
2	36%	46%	47%
3+	4%	24%	23%

Education

75% Have *graduated* college or university

- 1% Less than high school
- 7% Graduated high school
- 10% Some college/university
- 1% Other
- 5% Prefer not to answer

Household Income

Under $50,000	17%
$50,000-$99,999	27%
$100,000 +	35%
Prefer not to answer	21%

Gender

47% Woman 44% Man

1% Non-binary

7% Prefer not to answer



Every insight tells a story.



TVP Tariff Marketing & Recruitment

2024/25 (Year 4) Update
Prepared: March 3, 2025

March 3, 2025

TVP TARIFF MARKETING & RECRUITMENT

Summary

TVP Year 4 recruitment brought **innovation, success, learnings and opportunities**.

Although, we did not reach our enrollment targets, we **welcomed over 6,000 new participants** which brought the **total enrollment to over 8,860 customers.** This is a **189% increase** in total enrollment from the previous year**.**

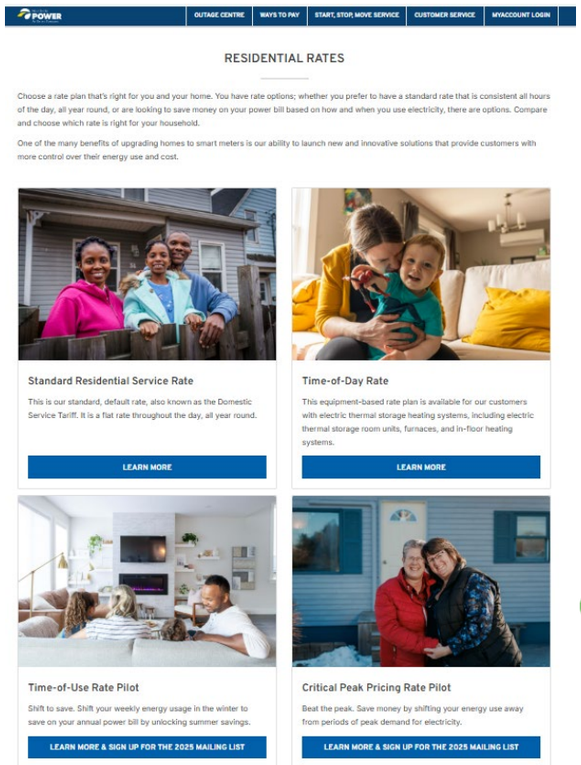
HIGHLIGHTS:

- Launched new rates branding
- Optimized and enhanced website experience
- Improved application process with Salesforce integrations
- Advanced and targeted email strategy
- Amplified customer reach & engagement with multi-channel paid outreach
- Introduced reporting and analytics (behaviour tracking and dashboards)
- New insights into next year’s approach



TVP TARIFF MARKETING & RECRUITMENT

New Rate Pages and Branding



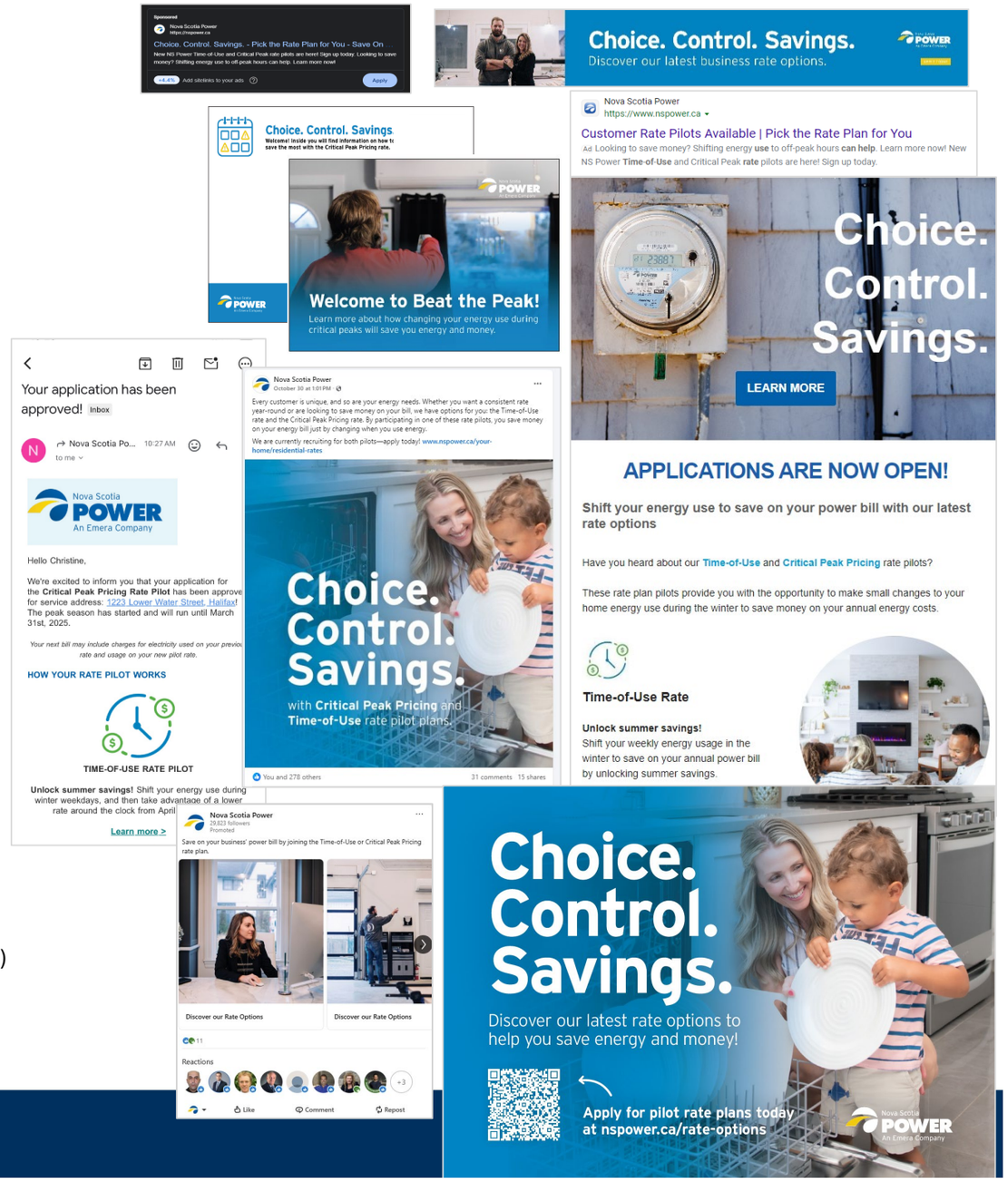




TVP TARIFF MARKETING & RECRUITMENT

Tactics and Schedule*

- **Email – October 22 – December 13**
  - Introduced Retargeting and Segmentation/Personalization
- **Paid Channels – October 21 – November 30, Extended until December 2**
  - Direct Mail Postcard
  - Digital Ads - Social, Google/Bing Display, Reddit, LinkedIn (SMB Only)
  - Paid Search – Google and Bing
  - Chamber Ads – Yarmouth and Cape Breton
- **Owned Channels – October 21 - December 15**
  - Web - Updated Content and Imagery
  - nspower.ca Home Page Banner
  - Time-of-Use Blog (which was featured in Nov/Dec E-Bills)
  - Social Media Posts
- **Internal Comms – October 3 – December 13**
  - Power to Learn (Webinar)
  - PowerGram (Internal Newsletter) and Digital Screens
  - Internal Referral Program
- **Earned Media – November 26** *(pitches begin)*
  - Radio - Info Morning Cape Breton Interview
- **Onboarding, Retention & Engagement**
  - Welcome Email (Automated)
  - TOU and CPP Residential Mailed Welcome Packages (delayed due to strike)
  - Engagement Emails (Tips and Progress)
  - Exit survey of past participants
  - *And much more! (more details in the appendix)*



TVP TARIFF MARKETING & RECRUITMENT

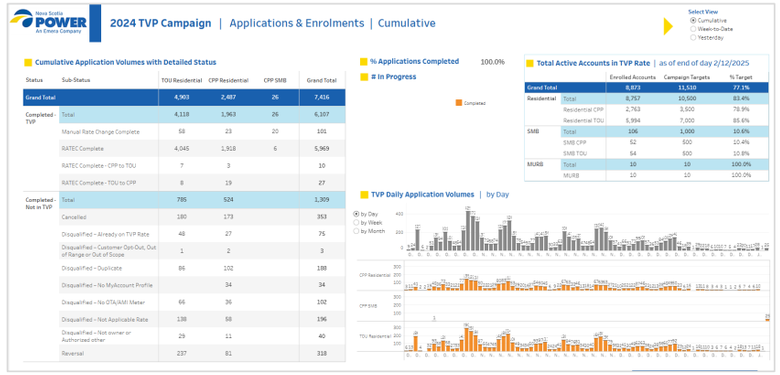
Reporting and Analytics

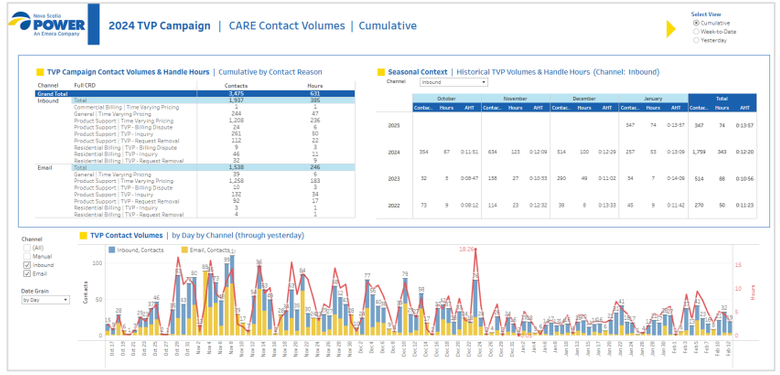
Over the last year, our business's marketing practices have advanced with the implementation of measurement models designed to effectively measure campaign performance.

As a result of this work, we introduced multi-level, multi-touchpoint metrics & data capturing for Year 4 recruitment, to efficiently monitor success.

RESULTS:

- Developed dashboards to monitor TVP recruitment, in real-time, which included metrics on applications, volume of TVP related inquires, and marketing efforts.
- Cross-functional teams were able to leverage this data to stay agile, which helped inform daily decisions on recruitment efforts.







Summary of Residential Recruitment Key Contacts

HIGHLIGHTS:

- The decrease in Average Time on Landing page is small and likely due to content updates being more efficient for the reader.
- Email generated 87% of new participants.
- Search, Display, Reddit outperformed industry benchmarks.
- Direct Mail had the longest lifespan – and still brings in web traffic to date.

Residential	YEAR 1	YEAR 2	YEAR 3	YEAR 4	
Email					**YOY %**
Emails Recipients	43,280	19,489	112,089	355,035	217% ↑
Email Opens	21,778	10,855	71,011	215133	203% ↑
Open Rate	50%	56%	63%	68%	8% ↑
Total Clicks	5,004	4,120	14,817	40845	176% ↑
Click Rate	23%	38%	21%	15%	-28% ↓
Conversion to Completed Application	N/A	N/A	N/A	87%	N/A
Web					
Total Views of Landing Pages	39,951	27,507	31,149	**98,909**	218% ↑
Total Average Time on Landing Pages	3m 41s	3m 55s	2m 47s	**2m 26s**	-9% ↓
TOU Landing Page Views				39,675	
Average Time on Page				2m 48s	
CPP Landing Page Views				32,627	
Average Time on Page				2m 21s	
Paid Search					
Google					
Impressions	N/A	N/A	9,079	69,722	87% ↑
Clicks	N/A	N/A	3,037	24,541	88% ↑
Click Through Rate (CTR)	N/A	N/A	33%	35.20%	5% ↑
Bing *NEW*					
Impressions	N/A	N/A	N/A	13,351	
Clicks	N/A	N/A	N/A	868	
Click Through Rate (CTR)	N/A	N/A	N/A	6.50%	
Paid Digital Ads (Google, Instagram, Facebook and Reddit)					
Impressions	N/A	3,084,248	N/A	8,661,954	
Clicks	N/A	14,483	N/A	34,632	
Click Through Rate (CTR)	N/A	0.60%	N/A	0.40%	
Direct Mail *NEW*					
Reach	N/A	N/A	N/A	200,000 homes	
Total Views of Landing Pages	N/A	N/A	N/A	7,729	
Average Time on Page	N/A	N/A	N/A	3m 39s	
Results					
Enrolment Target	1,000 TOU / 500 CPP	1,000 TOU / 500 CPP	2,000 TOU / 1,000 CPP	7,000 TOU / 3,500 CPP	
Applications Received	991 TOU / 351 CPP	474 TOU / 183 CPP	2,173 TOU / 837 CPP	4,703 TOU / 2,487 CPP	
Pilot Enrolment	667 TOU / 275 CPP	931 TOU / 384 CPP	2,000 TOU / 1,000 CPP	4,137 TOU / 1,973 CPP	
% of Target Achieved	76% TOU / 60% CPP	93% TOU / 77% CPP	100% / 100% CPP	85.7% TOU / 79.0% CPP	

Summary of Business Recruitment Key Contacts

HIGHLIGHTS:

- Although email opens/clicks decreased YoY, the click rate doubled – meaning the targeted content likely was more enticing.
- CTR for search is significantly higher than residential, suggesting that while search volume is lower, business users demonstrate higher intent and engagement when they do search online.

Business	YEAR 1	YEAR 2	YEAR 3	YEAR 4	
Email					**YOY %**
Emails Recipients	4,136	6,914	6,216	503	-1136% ↓
Email Opens	1,729	3,254	3,264	236	-1283% ↓
Open Rate	42%	47%	53%	47%	-12% ↓
Total Clicks	189	445	324	59	-449% ↓
Click Rate	11%	14%	10%	25%	60% ↑
Web					
Total Views of Landing Pages	39,951	27,507	31,149	18,978	
Total Average Time on Landing Pages	3m 41s	3m 55s	2m 47s	1m	
Paid Search					
Google					
Impressions	N/A	N/A	9,079	1,402	
Clicks	N/A	N/A	3,037	587	
Click Through Rate (CTR)	N/A	N/A	33%	41.87%	
Bing *NEW*					
Impressions	N/A	N/A	N/A	1,015	
Clicks	N/A	N/A	N/A	67	
Click Through Rate (CTR)	N/A	N/A	N/A	6.60%	
Paid Digital Ads (Google Display and LinkedIn)					
Impressions	N/A	995,163	N/A	1,808,132	
Clicks	N/A	1,483	N/A	3,314	
Click Through Rate (CTR)	N/A	0.15%	N/A	0.33%	
2024 Q4 - Contactor Newsletter					
Email Recipients	N/A	N/A	129	170	
Chamber of Commerce Newsletters / Advertising					
Yarmouth Chamber of Commerce	N/A	N/A	N/A	Over 300 members	
Cape Breton Chamber Reach	N/A	N/A	N/A	3,100 subscribers	
Results					
Enrolment Target	500 TOU / 500 CPP	500 TOU / 500 CPP	500 TOU / 500 CPP	500 TOU / 500 CPP	
Applications Received	33 TOU / 10 CPP	25 TOU / 8 CPP	35 TOU / 7 CPP	0 TOU / 26 CPP	
Pilot Enrolment	29 TOU / 9 CPP	40 TOU / 9 CPP	62 TOU / 10 CPP	54 TOU / 53 CPP	
% of Target Achieved	3% TOU / 1% CPP	4% TOU / 1% CPP	6% TOU / 1% CPP	11% TOU / 11% CPP	

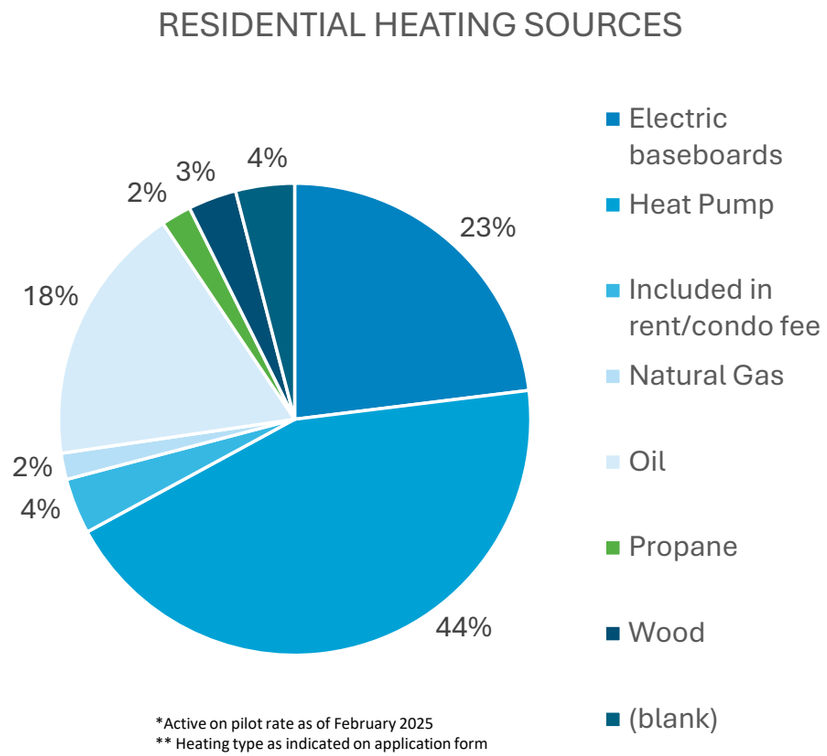
TVP TARIFF MARKETING & RECRUITMENT

Residential Recruitment

	TOU (Rate 80, 81)	CPP (Rate 70, 71)	Residential Total
Enrollment Target	7,000	3,500	10,500
Year 4 New Applications	4,703	2,487	7,416
Year 4 Accepted New Applications	4,137	1,973	6,136
Enrollment (As of January 9, 2025)	5,999	2,764	8,763

HIGHLIGHTS

- 83.5% of the Residential Enrollment Target was achieved
  - 85.7% of TOU Rate target
  - 79.0% of CPP Rate target
- Of the approved participants, approximately 11% meet the Low-Income Cutoff (LCL).
- 85% of participants agreed to participate in surveys throughout the pilot.
- Close to 67% of pilot participants identified they heat their homes electrically (i.e., baseboards, heat pump) on the application form. This is a 1% increase from last year.



TVP TARIFF MARKETING & RECRUITMENT

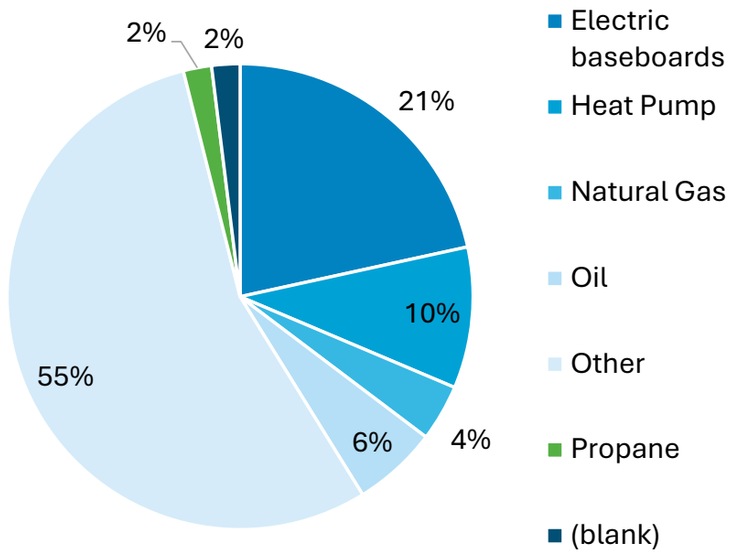
SMB Recruitment

	TOU (Rate 82, 83)	CPP (Rate 72, 83)	Commercial Total
Enrollment Target	500	500	1,000
Year 4 New Applications	0	26	26
Enrollment (As of January 9, 2025)	54	53	107

HIGHLIGHTS

- New participants from 2025 came from our Business Solutions team. Our Commercial Advisors leveraged the TVP rates in customer conversations.
    - This customized recruitment approach will be utilized in year 5 as it appears to be the key to SMB Recruitment.
- 20% of Business Enrollment Targets were achieved.
- The top business sectors the pilot participants belong to: Retail Stores, Recreation, Restaurants, Automotive, Accommodation
- Close to 31% of pilot participants identified they heat electrically (i.e., baseboards, heat pump) on the application form. This is a 34% decrease from last year.
- 84% of participants agreed to participate in surveys throughout the pilot.

BUSINESS HEATING SOURCES



*Active on pilot rate as of February 2025
** Heating type as indicated on application form

TVP TARIFF MARKETING & RECRUITMENT

MURB Recruitment

	MURB Rate
Enrollment Target	10
Year 4 New Applications	10
Enrollment (As of January 9, 2025)	10

HIGHLIGHTS

- 100% of the MURB Enrollment Target was achieved
  - 10 General Demand house meter customers were recruited for the Pilot
  - These buildings are representative of ~1000 residential suite meters
- Recruitment was conducted through direct outreach to customers, many of whom participated in the MURB Stakeholder Sessions in 2024.
- NS Power's Customer Solutions team worked directly with MURB stakeholders to analyze their buildings' potential to shift load.
- Pilot participants are representative of a variety of heating and domestic hot water systems including:
  - Air to Water Heat Pumps
  - Hot Water Baseboard
  - Natural Gas Boilers
- Pilot participant building sizes range from <50 units to >200 residential units

TVP TARIFF MARKETING & RECRUITMENT

Year 4 – Challenges and Opportunities

CHALLENGES

- **Canada Post Strike –** Limited ability to push larger batches of customer outreach due to Customer Care Centre focused on Canada Post campaign. Additionally, marketing could not complete any subsequent direct mail drops which proved to be a successful tactic.
- **Timeline -** As approval was given to extend the Pilot for Year 4 in late October, recruitment started later than expected. It progressed into the season adding some complications and applications dipped leading into the holidays.

OPPORTUNITIES

- **SMB Recruitment –** Traditional marketing efforts showed inefficient for SMB recruitment. Conversations with trusted advisors (NS Power Commercial Advisors) proved to be the most effective tactic.
- **Channels & Timing –** Longer lead times and recruitment periods to drive more interest and applications, in addition to adding more marketing channels and touchpoints with customers.

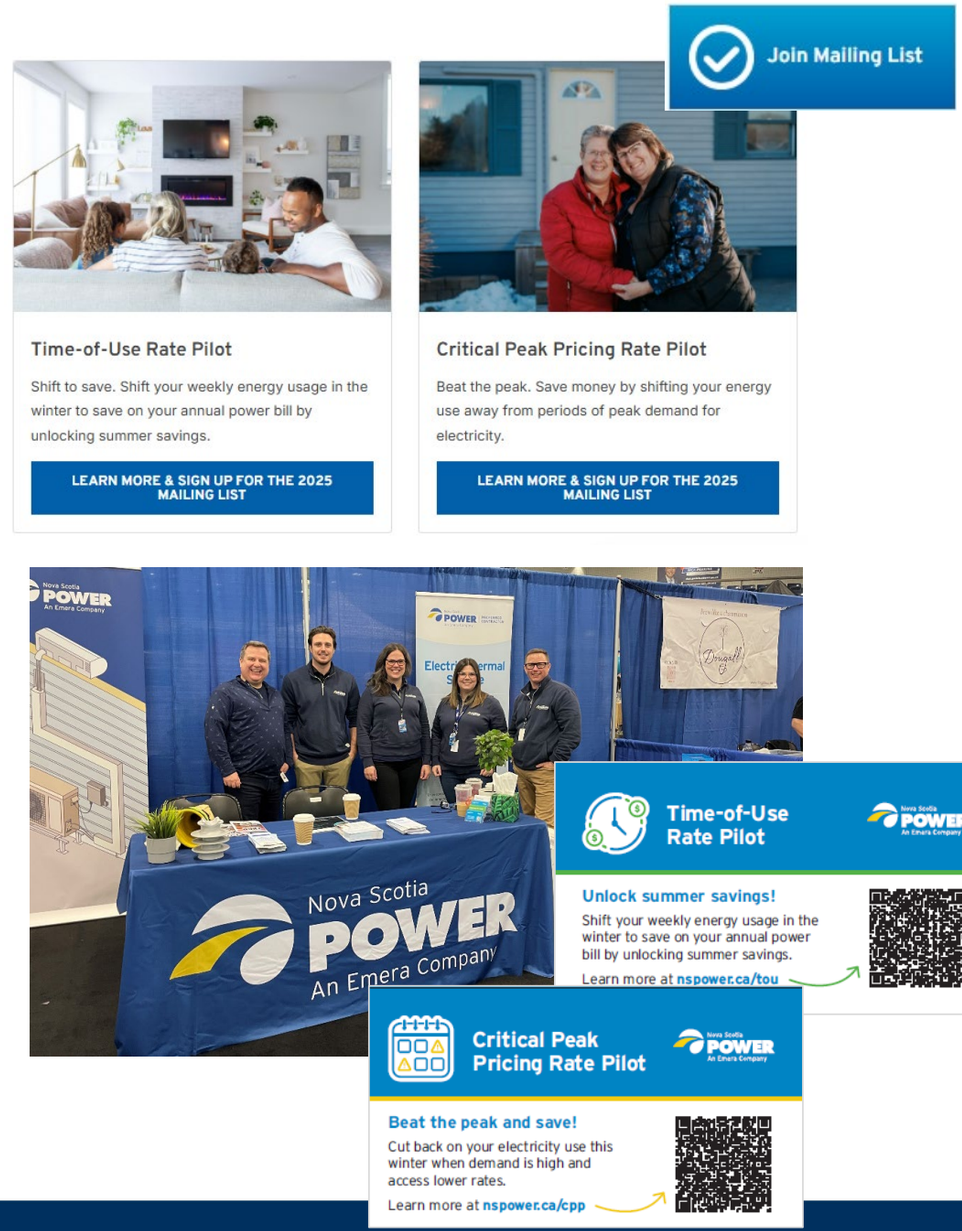
TVP TARIFF MARKETING & RECRUITMENT

Closing Thoughts

As a result of the Year 4 learnings, the team will continue to adapt and evolve our engagement and recruitment efforts to deliver value for our customers.

We will:

- Continue to encourage sign-ups for the TVP mailing list on our rate pilot landing pages through customer conversations and public events. At the time of this report, **there are currently over 560 Customers signed up.**
- Roll out ongoing customer engagement plans to maintain retention and demonstrate value to our pilot customers.
- Grow awareness, consideration and sign-ups for our TVP rates to our standard residential customers.
- Continuously improve application process and marketing efforts, we have conducted an exit survey for those who left the rate pilot. These findings will be presented and considered in Year 5 planning.





Appendix

Marketing Tactics & Results

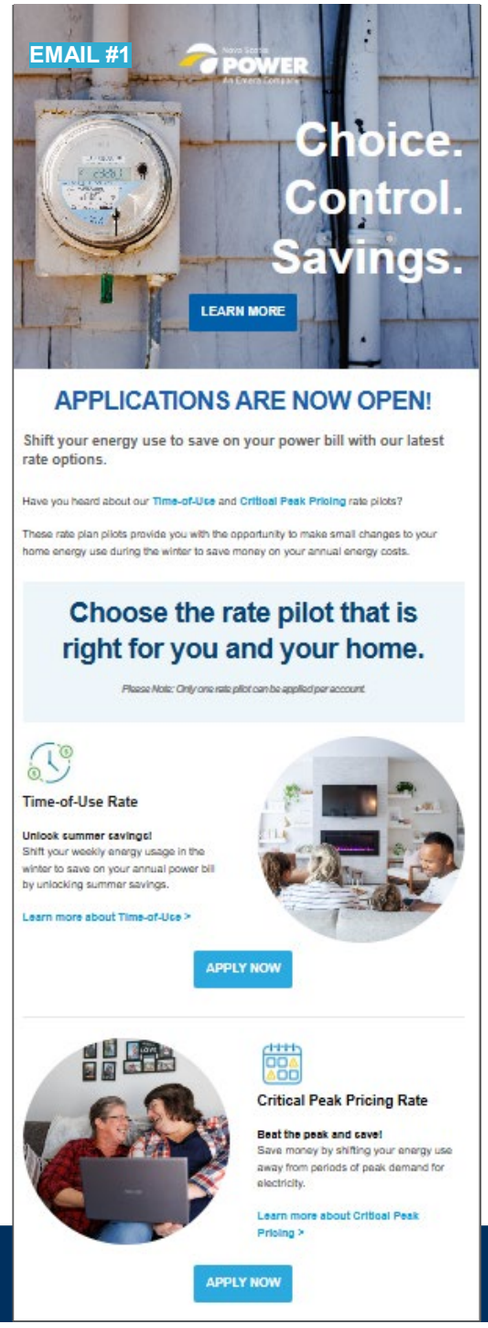
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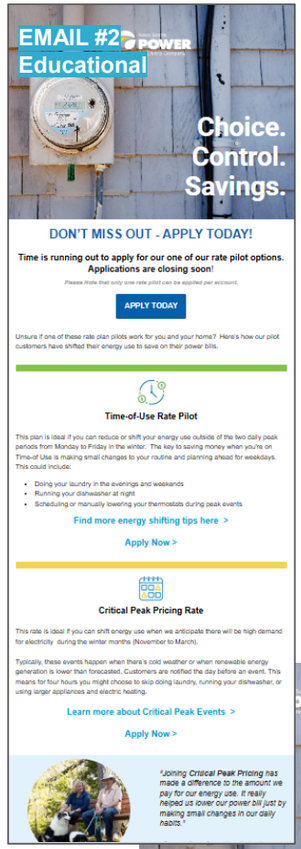
APPENDIX | MARKETING TACTICS & RESULTS

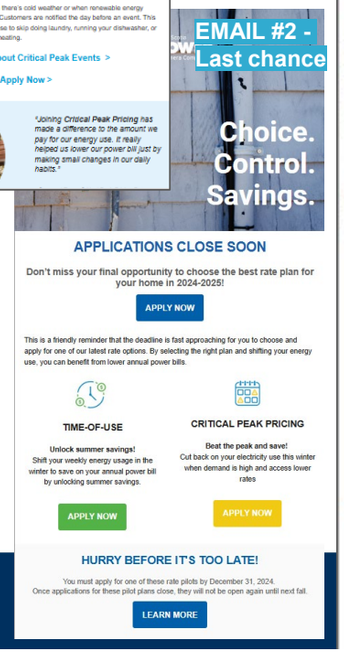
Email

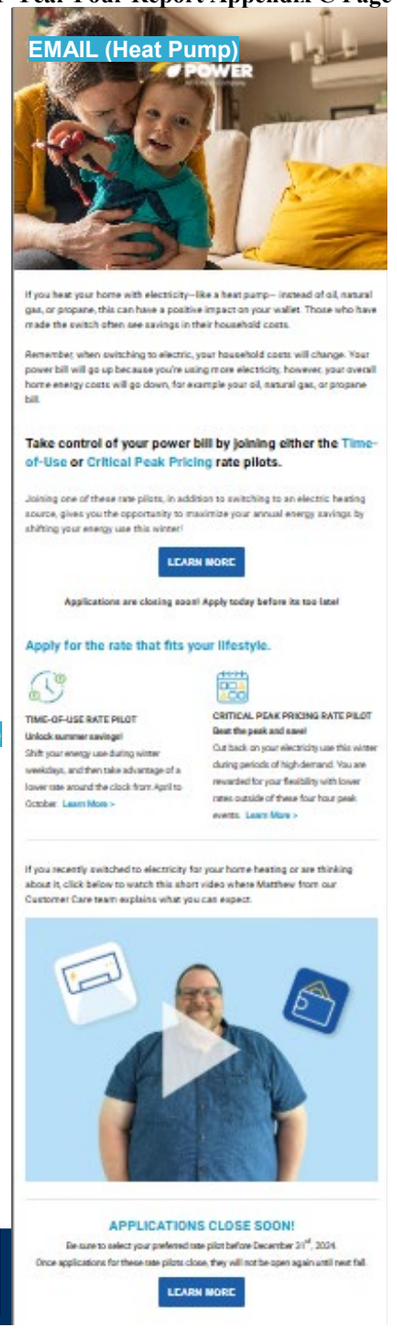
Residential

- Strongest recruitment tactic accounting for 87% of new participants in year 4.
- Ran from Oct 22 – Dec 15 with emails to over 355K Residential Customers.
- Highest Click Rate and Open Rate occurred with Email 2 – to a segment of customers who opened and engaged with Email 1 but didn't apply (Email #2 Educational)







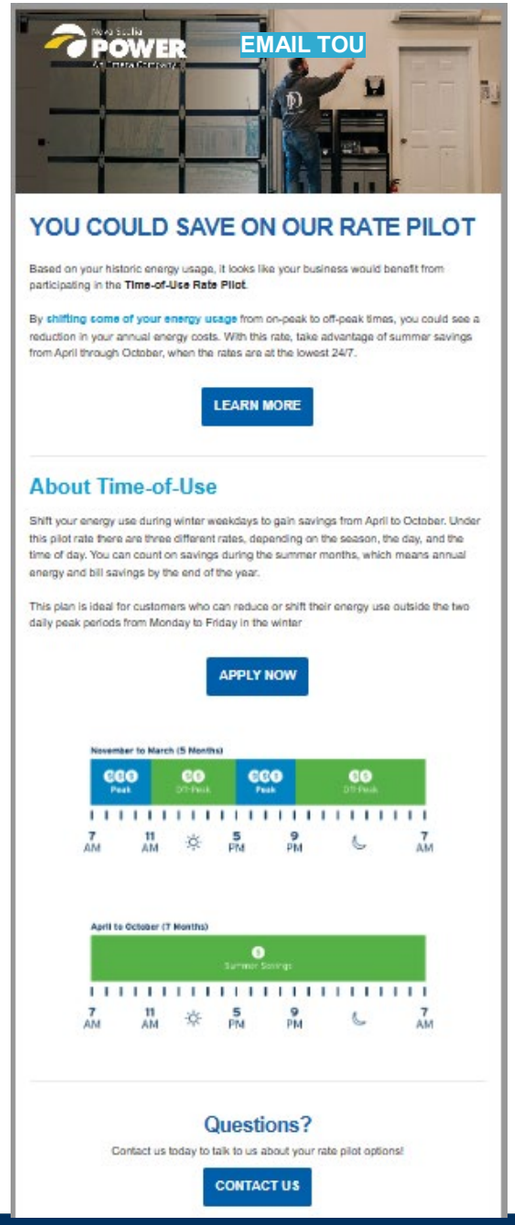


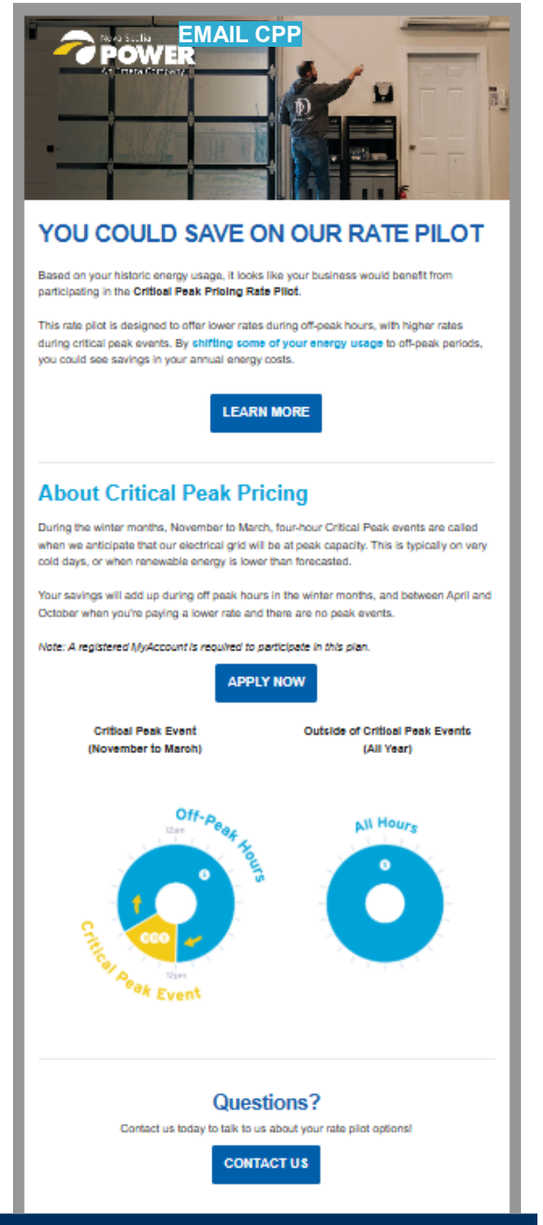
APPENDIX | MARKETING TACTICS & RESULTS

Email

Business

- Although sent to a small number of SMB customers, these were personalized which resulted in the highest Click Rate for SMB Emails.
- LEARN MORE and APPLY NOW were the most clicked CTAs



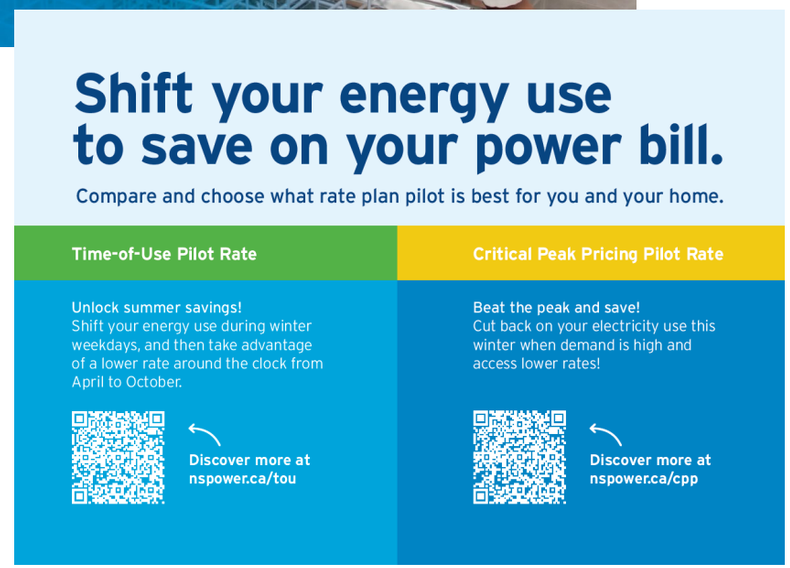


APPENDIX | MARKETING TACTICS & RESULTS

Direct Mail

- Second strongest marketing tactic.
- Recruitment postcard, sent as a Neighborhood Mail piece, reached 200,000 single-dwelling homes.
- This campaign generated 7,729 website sessions via the QR Code
- Continuing to drive traffic to the website even after recruitment.





APPENDIX | MARKETING TACTICS & RESULTS

Paid Digital Advertising

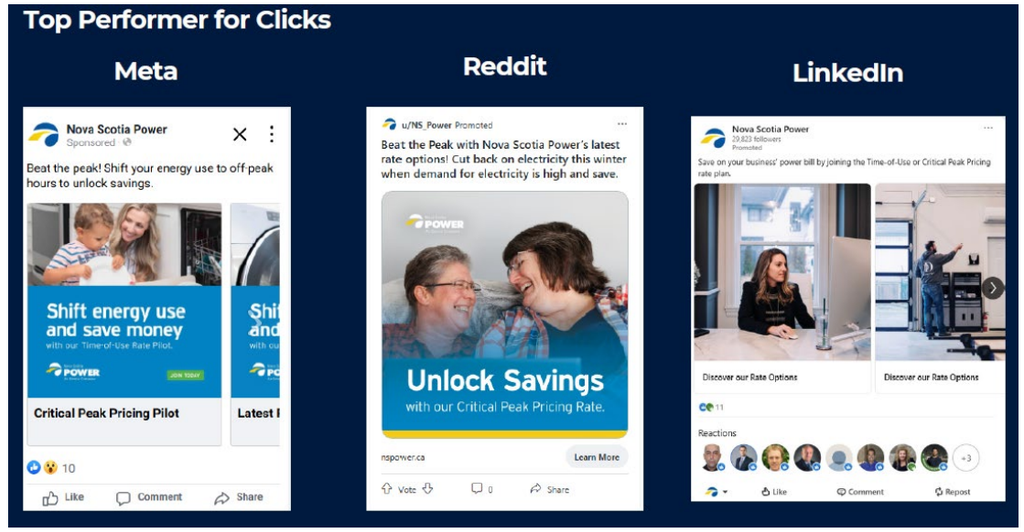
- Ran from Oct 21 – November 30, Extended until December 2

Residential

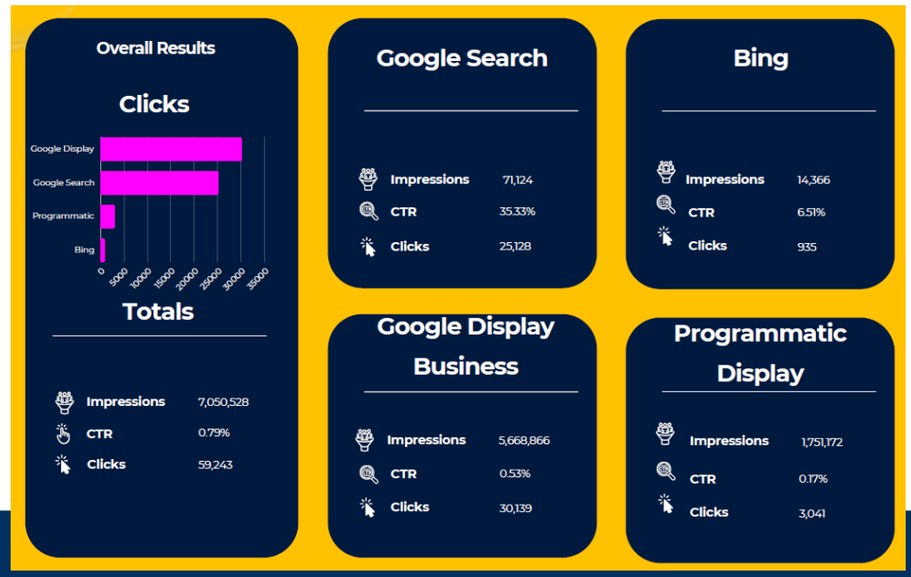
- SEM and Display
- Paid Social
  - Facebook
  - Instagram
  - Reddit

Business

- SEM and Display
- Paid Social
  - LinkedIn



Paid Display and SEM



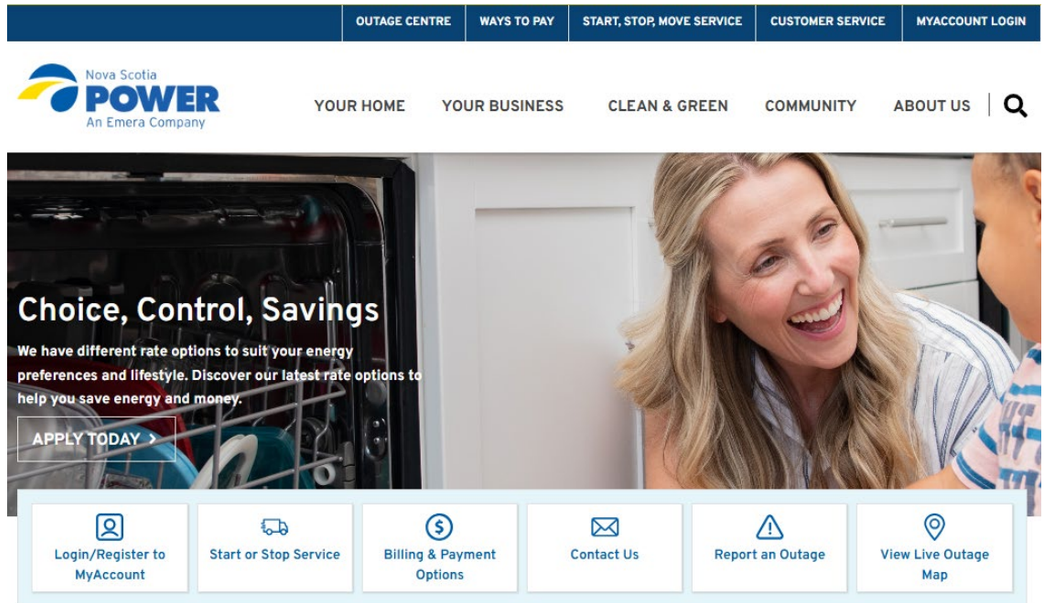
Paid Social



APPENDIX | MARKETING TACTICS & RESULTS

Website

- Web Updates:
  - Individual Rate Pages Created
  - Content and Visuals Updates
- Increase webpage referrals
  - Save Energy and Money
  - Rate Options
  - Home Page Banner – November 28 – December 15, 2024

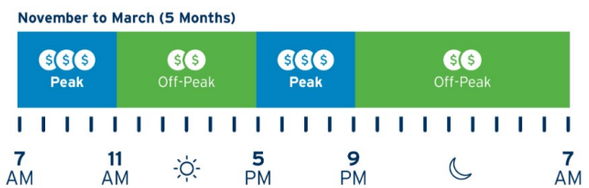


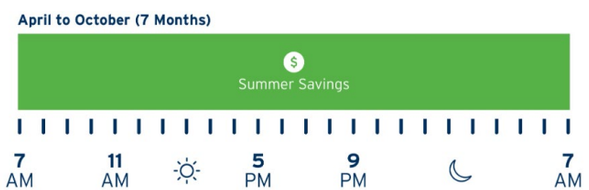
APPENDIX | MARKETING TACTICS & RESULTS

Residential Rate Branding

TIME-OF-USE RATE PILOT

nspower.ca/tou





CRITICAL PEAK PRICING RATE PILOT

nspower.ca/cpp

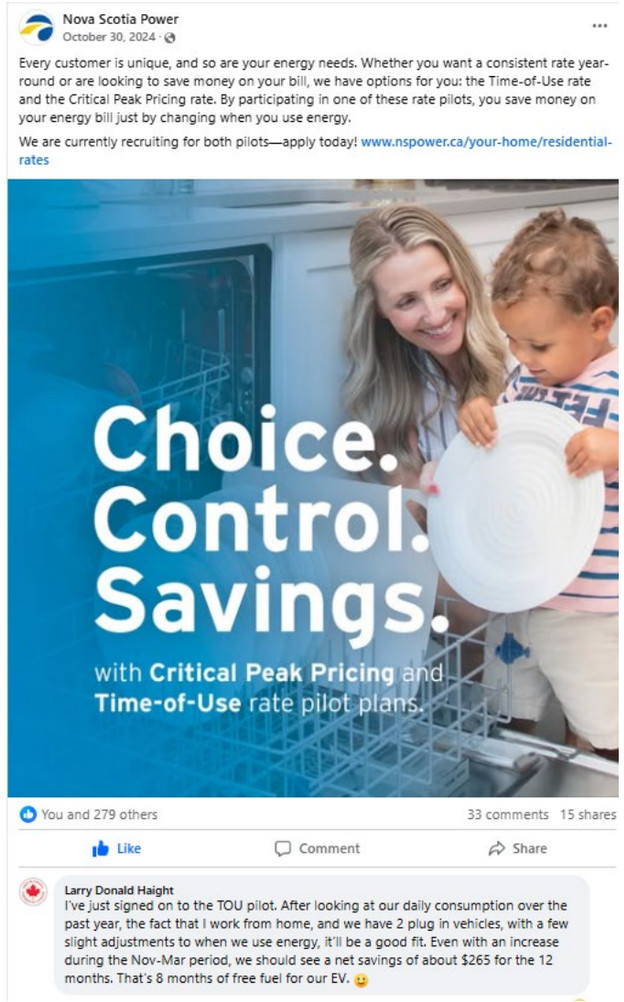


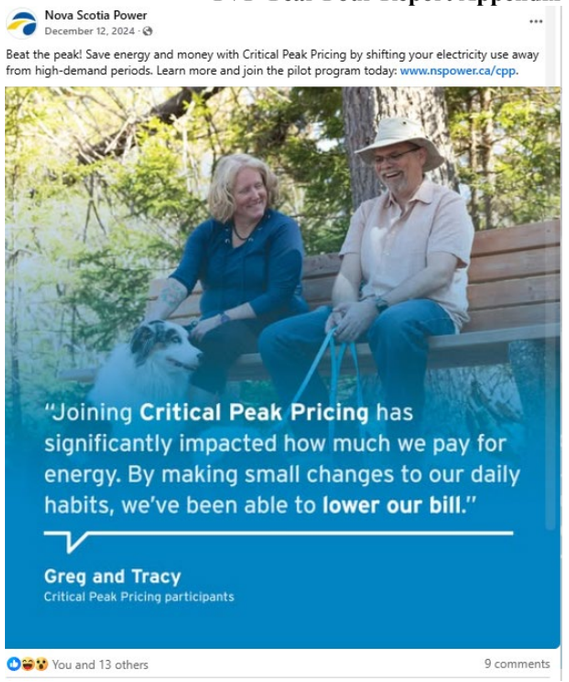


APPENDIX | MARKETING TACTICS & RESULTS

Social Media

- Social Media Posts - October 30, November 21 & December 12, 2024





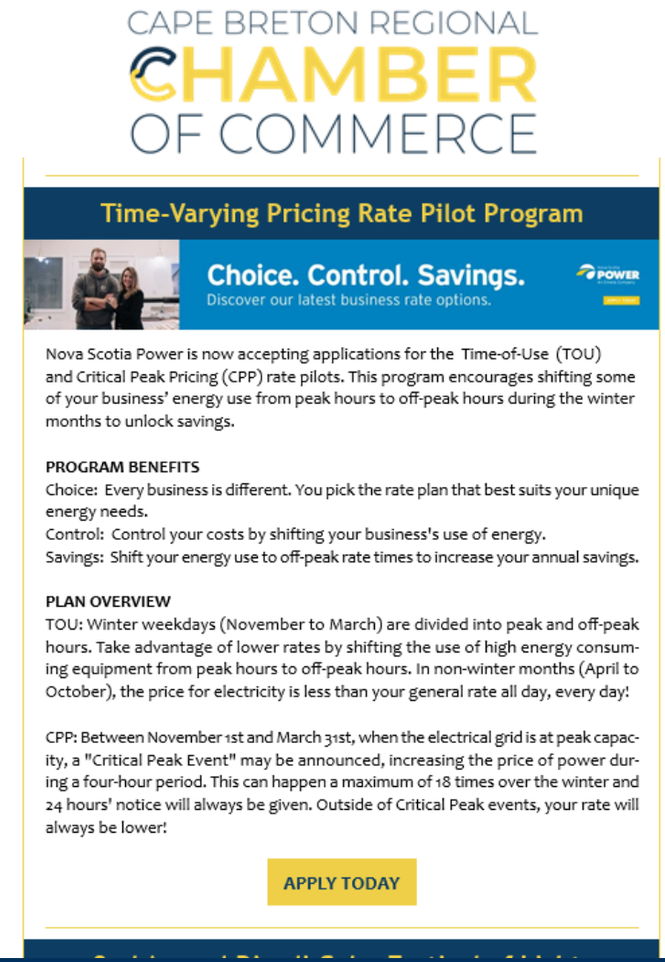


APPENDIX | MARKETING TACTICS & RESULTS

Chamber of Commerce

- We submitted content and banner ads to be featured in October issues of the Yarmouth Chamber of Commerce Bi-Weekly Newsletter and Cape Breton Chamber of Commerce Monthly.
- View Yarmouth Newsletter
- Cope of Cape Breton Newsletter available upon request





APPENDIX | MARKETING TACTICS & RESULTS

Internal Engagement



- Power to Learn (Internal Webinar) – October 3, 2025
  - 220 Attendees
- PowerGram Feature – November 15, 2024
- Internal Referral Program – November 15 – December 13 , 2024
  - 133 Participants



EMPLOYEE EXPERIENCE

Off Peak Perks Employee Referral Program Contest

A reminder about the *Off Peak Perks Referral Program*, a referral contest for both Nova Scotia Power and Emera employees - to support as many customers as possible to sign onto one of our rate pilot programs: Time-of-Use Rate Pilot or Critical Peak Pricing Pilot. These pilot rates help customers to save money by having more control over their energy use and costs. The goal is for 10,500 residential customers to join one of the pilot programs, and we are approximately half-way to that goal.

For each customer you refer who officially signs-up for one of these pilots, you will receive one entry for a chance to win a prize package valued at $500.00! There is no limit on referrals. How ever many people you refer who follow-through and sign-up for the pilot on their account, you have the same number of prize entries.

The winner of the draw will get to choose from one of the following packages:

- Smart Home Power Package
- iPad mini (6th gen)
- Active package: Wireless headphones & smart watch
- Nova Scotia Power Inc. swag bag

Use this form to submit your referrals by December 13: Off Peak Perks Referral Program referral form

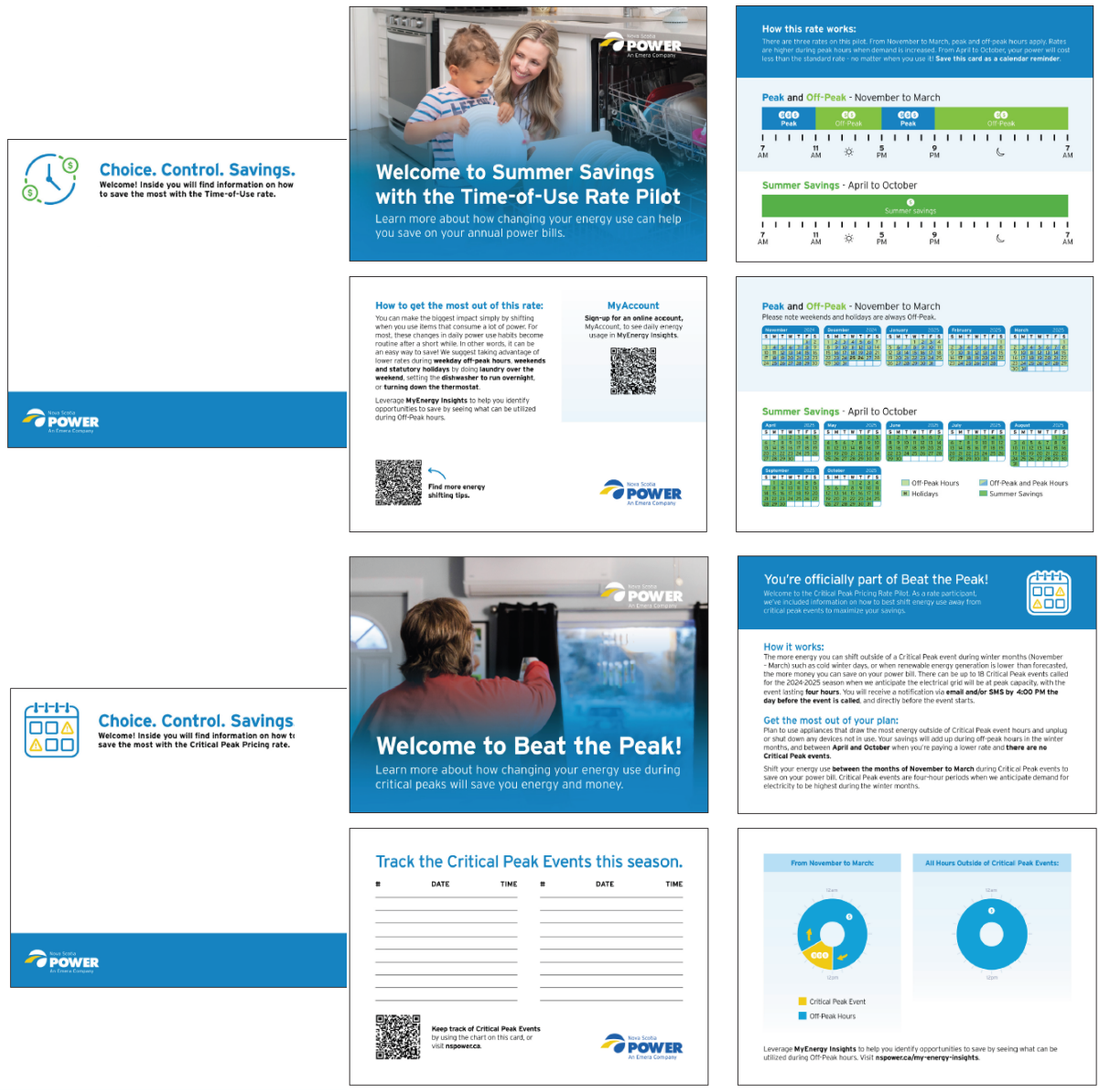
The draw will be held December 16 with the winner being announced in Powergram.

For questions about the pilots, please contact: James Young, Senior Rate Design Specialist at james.young@nspower.ca And for questions about the referral process reach out to Courtney.Carter@nspower.ca

APPENDIX | MARKETING TACTICS & RESULTS

Welcome Packages

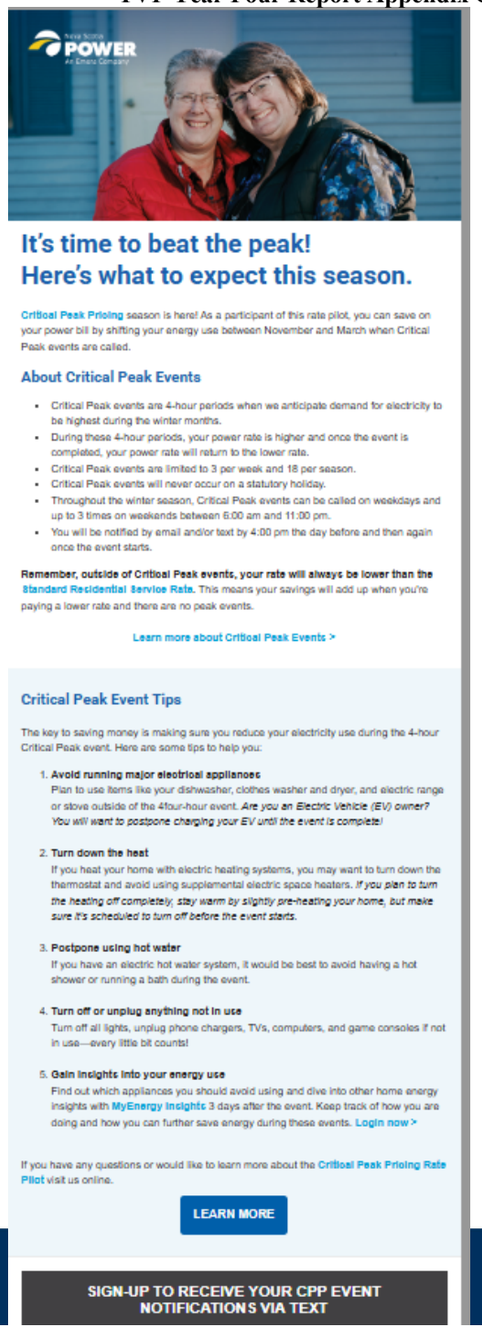
- Sent to over 8K customers
- Focused on providing a value add with helpful tips and tricks to be successful on the plans.
- A customer called in after receiving welcome package who just days before left the program. They said the welcome letter made a positive impact and now want to rejoin after getting the mail because they feel they understand the program better



APPENDIX | MARKETING TACTICS & RESULTS

Engagement

- Sent a Critical Peak Event Prep Email
- Plan to send season complete email, and push more social media to help support



It's time to beat the peak!
Here's what to expect this season.

Critical Peak Pricing season is here! As a participant of this rate pilot, you can save on your power bill by shifting your energy use between November and March when Critical Peak events are called.

About Critical Peak Events

- Critical Peak events are 4-hour periods when we anticipate demand for electricity to be highest during the winter months.
- During these 4-hour periods, your power rate is higher and once the event is completed, your power rate will return to the lower rate.
- Critical Peak events are limited to 3 per week and 18 per season.
- Critical Peak events will never occur on a statutory holiday.
- Throughout the winter season, Critical Peak events can be called on weekdays and up to 3 times on weekends between 6:00 am and 11:00 pm.
- You will be notified by email and/or text by 4:00 pm the day before and then again once the event starts.

Remember, outside of Critical Peak events, your rate will always be lower than the Standard Residential Service Rate. This means your savings will add up when you're paying a lower rate and there are no peak events.

Learn more about Critical Peak Events >

Critical Peak Event Tips

The key to saving money is making sure you reduce your electricity use during the 4-hour Critical Peak event. Here are some tips to help you:

1. **Avoid running major electrical appliances**
   Plan to use items like your dishwasher, clothes washer and dryer, and electric range or stove outside of the 4four-hour event. *Are you an Electric Vehicle (EV) owner? You will want to postpone charging your EV until the event is complete!*
2. **Turn down the heat**
   If you heat your home with electric heating systems, you may want to turn down the thermostat and avoid using supplemental electric space heaters. *If you plan to turn the heating off completely, stay warm by slightly pre-heating your home, but make sure it's scheduled to turn off before the event starts.*
3. **Postpone using hot water**
   If you have an electric hot water system, it would be best to avoid having a hot shower or running a bath during the event.
4. **Turn off or unplug anything not in use**
   Turn off all lights, unplug phone chargers, TVs, computers, and game consoles if not in use—every little bit counts!
5. **Gain insights into your energy use**
   Find out which appliances you should avoid using and dive into other home energy insights with **MyEnergy Insights** 3 days after the event. Keep track of how you are doing and how you can further save energy during these events. **Login now >**

If you have any questions or would like to learn more about the **Critical Peak Pricing Rate Pilot** visit us online.

LEARN MORE

SIGN-UP TO RECEIVE YOUR CPP EVENT NOTIFICATIONS VIA TEXT


Nova Scotia
POWER
An Emera Company
FIRE-RESCUE

					Phase 1: 2021/2022 (Cohort 1)				
Rate Class	**Tariff (Tariff #)**	**August**	**September**	**October**	**November**	**December**	**January**	**February**	**March**
Domestic	TOU (Rate 80,81)	202	461	723	741	724	702	686	678
Small General	TOU (Rate 82)	-	7	10	11	18	18	17	16
General Demand	TOU (Rate 83)	-	5	9	10	13	13	13	13
General Demand	MURB TOU (Rate 89)								
TOTAL TVP		**202**	**473**	**742**	**762**	**755**	**733**	**716**	**707**
Domestic	CPP (Rate 70,71)	89	192	277	287	287	283	281	278
Small General	CPP (Rate 72)	-	1	4	4	4	4	4	4
General Demand	CPP (Rate 73)	-	2	5	5	5	5	5	5
TOTAL CPP		**89**	**195**	**286**	**296**	**296**	**292**	**290**	**287**
Total Customers on TVP Pilot Tariffs		**291**	**668**	**1,028**	**1,058**	**1,051**	**1,025**	**1,006**	**994**

		Phase 2: 2022/2023 (Cohorts 1 & 2)											
Rate Class	**Tariff (Tariff #)**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**January**	**February**	**March**
Domestic	TOU (Rate 80,81)	676	666	658	653	647	644	639	926	918	905	899	896
Small General	TOU (Rate 82)	16	16	16	16	16	16	16	30	30	29	29	29
General Demand	TOU (Rate 83)	13	13	13	13	13	13	13	14	12	12	12	12
General Demand	MURB TOU (Rate 89)												
TOTAL TVP		**705**	**695**	**687**	**682**	**676**	**673**	**668**	**970**	**960**	**946**	**940**	**937**
Domestic	CPP (Rate 70,71)	277	275	269	267	267	262	261	379	380	376	375	374
Small General	CPP (Rate 72)	4	4	4	4	4	4	4	5	5	5	5	5
General Demand	CPP (Rate 73)	5	5	5	5	5	5	5	6	5	5	5	5
TOTAL CPP		**286**	**284**	**278**	**276**	**276**	**271**	**270**	**390**	**390**	**386**	**385**	**384**
Total Customers on TVP Pilot Tariffs		**991**	**979**	**965**	**958**	**952**	**944**	**938**	**1,360**	**1,350**	**1,332**	**1,325**	**1,321**

		Phase 3: 2023/2024 (Cohorts 1, 2 & 3)											
Rate Class	**Tariff (Tariff #)**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**January**	**February**	**March**
Domestic	TOU (Rate 80,81)	885	879	872	867	857	854	846	1,223	2,296	2,302	2,269	2,258
Small General	TOU (Rate 82)	29	29	29	29	29	29	28	30	39	38	37	37
General Demand	TOU (Rate 83)	12	12	12	12	12	12	12	12	20	20	19	19
General Demand	MURB TOU (Rate 89)												
TOTAL TVP		**926**	**920**	**913**	**908**	**898**	**895**	**886**	**1,265**	**2,355**	**2,360**	**2,325**	**2,314**
Domestic	CPP (Rate 70,71)	372	371	370	368	365	363	361	551	904	927	924	919
Small General	CPP (Rate 72)	5	5	5	5	5	5	5	5	4	4	4	3
General Demand	CPP (Rate 73)	5	5	5	5	5	5	5	6	6	6	6	6
TOTAL CPP		**382**	**381**	**380**	**378**	**375**	**373**	**371**	**562**	**914**	**937**	**934**	**928**
Total Customers on TVP Pilot Tariffs		**1,308**	**1,301**	**1,293**	**1,286**	**1,273**	**1,268**	**1,257**	**1,827**	**3,269**	**3,297**	**3,259**	**3,242**

		Phase 4: 2024/2025 (Cohorts 1, 2, 3 & 4)											
Rate Class	**Tariff (Tariff #)**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**January**	**February**	**March**
Domestic	TOU (Rate 80,81)	2,245	2,231	2,222	2,209	2,195	2,173	2,161	5,162	5,888	5,776	5,762	5,681
Small General	TOU (Rate 82)	36	36	36	36	35	35	35	35	37	36	38	38
General Demand	TOU (Rate 83)	19	19	19	19	19	19	19	19	19	18	18	18
General Demand	MURB TOU (Rate 89)	-	-	-	-	-	-	-	10	10	10	10	10
TOTAL TVP		**2,300**	**2,286**	**2,277**	**2,264**	**2,249**	**2,227**	**2,215**	**5,226**	**5,954**	**5,840**	**5,828**	**5,747**
Domestic	CPP (Rate 70,71)	915	910	907	900	891	885	880	2,330	2,711	2,696	2,683	2,658
Small General	CPP (Rate 72)	3	3	3	3	3	3	3	3	12	17	17	17
General Demand	CPP (Rate 73)	6	6	6	6	6	6	5	6	18	36	36	36
TOTAL CPP		**924**	**919**	**916**	**909**	**900**	**894**	**888**	**2,339**	**2,741**	**2,749**	**2,736**	**2,711**
Total Customers on TVP Pilot Tariffs		**3,224**	**3,205**	**3,193**	**3,173**	**3,149**	**3,121**	**3,103**	**7,565**	**8,695**	**8,589**	**8,564**	**8,458**


NS Power TVP Pilot –
Year Three Evaluation Review & 2024/25 Areas of Focus Kickoff Session
November 27, 2024
Nova Scotia POWER
An Emera Company

Agenda

1. Welcome & Introduction
2. TVP Tariff Development Cycle
3. Review of Year Three Evaluation Report Results – Econoler
4. Review of Draft List of Proposed MURB TOU Tariff Evaluation Metrics
5. Draft 2024/25 Areas of Focus Work Plan for Discussion
6. Near Term Next Steps

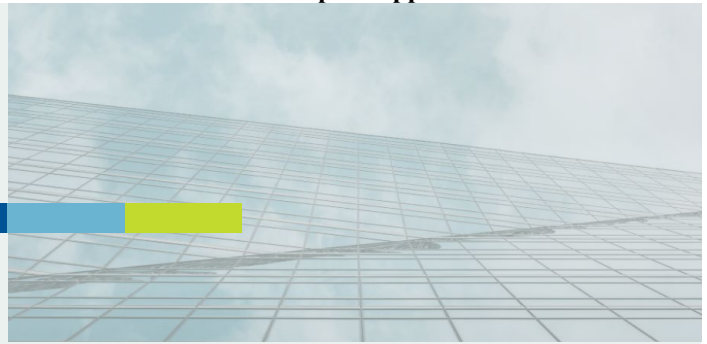
TVP Tariff Development Cycle

- As provided in the 2024 TVP Consensus Agreement – the Company will continue to manage and refine its TVP Program in a structured, analytics-based, and stakeholder engaged manner focusing on an annual TVP development, approval and implementation cycle including, for each year:

November	Winter/Spring	Spring/Summer	Summer/Autumn
• Effective date for TVP tariff changes • Enrolment cut-off for coming winter period	• Data collection and monitoring of TVP program performance • Development of program refinements	• Measurement, evaluation, and reporting on TVP Tariff results • Presentation and application for approval of changes to TVP tariffs	• Marketing and recruitment of TVP customers

- Across this annual cycle the Company will maintain ongoing stakeholder engagement such that stakeholders are provided with the information required to remain informed of the TVP Program progress and prepared to provide input on the TVP Program strategy and proposed changes to the TVP Tariff offerings


Review of Year Three (2023/24)
TVP Evaluation Results
Nova Scotia
POWER
An Emera Company



Nova Scotia Power Engagement Session

TIME-VARYING PRICING PILOT PHASE 3 EVALUATION

NOVEMBER, 2024

ECONOLER

PRESENTATION OBJECTIVE

Explain key methodological changes in TVP Year 3 results and updated findings.

ECONOLER

METHODOLOGY

ECONOLER

What we measured

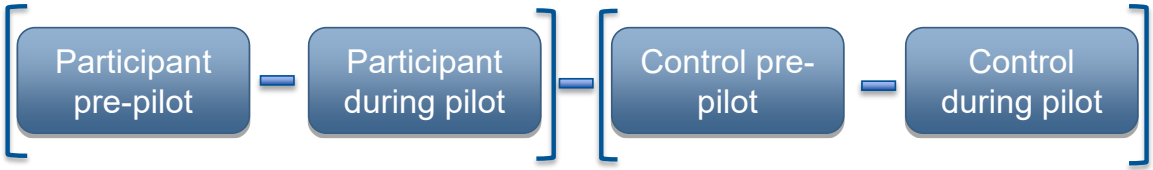
Same metrics as in Phase 2

- Change in load (power - kW) during peak periods: how much were participants able to reduce their consumption when it mattered
- Change in energy usage levels (kWh): how much energy did participants save in total on peak days
- Bill impacts ($): how much did participants save on their electricity bills

ECONOLER

Overview of Methodology - TOU

Comparing participants' electricity consumption during TVP to their own consumption **before TVP**, and using a control group to subtract any changes in consumption that is not due to the TVP pilot (e.g. different weather, changes in economic conditions, increased adoption of energy efficiency, etc.).

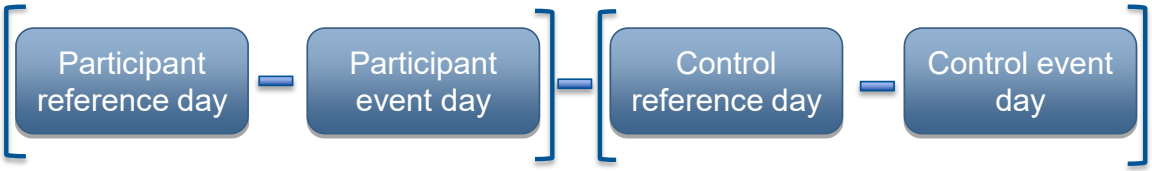


Control group: non-TVP participants selected among NS Power customers that have a similar consumption level and geographical location to TVP participants, as well as similar participation levels in Efficiency Nova Scotia programs.

ECONOLER

Overview of Methodology - CPP

General idea: Same as TOU, except that event days are compared to reference days (days with similar weather when no events were called)



ECONOLER

Methodology Change – Participant Segmentation

Instead of only using the baseline period to determine space heating types, in Phase 3 participants were categorized based on both their pre- and post-participation space heating type.

Participant Segment	Space Heating Pre-Participation	Space Heating Post-Participation
Steady electric	Electric	Electric
Electrified	Non-electric	Electric
De-electrified	Electric	Non-electric
Steady non-electric	Non-electric	Non-electric

ECONOLER

RESULTS – RESIDENTIAL CUSTOMERS

ECONOLER

Pilot Enrollment

Tariff	Active Participants			Percentage of Enrolled Participants Who Completed Year 3
	End of Phase 2 Winter	Beginning of Phase 3 Winter	End of Phase 3 Winter	
Residential TOU	891	2,396	2,241	93.5%
Residential CPP	373	950	922	97.1%

The percentage of participants that exit the tariff is slightly lower for CPP.

ECONOLER

TOU Impacts – Load During Peak

Parameters	Morning Peak				Evening Peak			
	Year 1	Year 2	Year 3	All	Year 1	Year 2	Year 3	All
Average Load Reduction During Peak Hours (kW)	0.218 ± 0.071	0.193 ± 0.109	0.078 ± 0.038	**0.154 ± 0.033**	0.253 ± 0.055	0.167 ± 0.093	0.074 ± 0.032	**0.153 ± 0.026**
Average Load – TOU Participants, Pre-Pilot (kW)	1.751	2.404	2.085	**2.073**	1.936	2.463	2.175	**2.173**
Relative Average Load Reduction (%)	12.5%	8.0%	3.7%	**7.4%**	13.1%	6.8%	3.4%	**7.0%**

- Participants enrolled in Year 1 and 2 have similar savings, but participants enrolled in Year 3 have significantly less savings
- A good proportion of that decrease in performance is due to the difference in space heating scenario mix: when adjusting for the same space heating scenario mix as Year 1, Year 3 results are only approximately 25% lower

ECONOLER

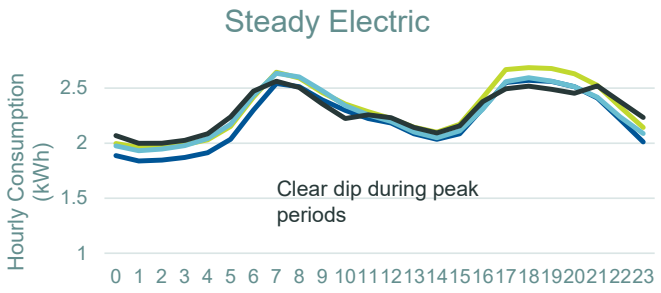
TOU Impacts – Load During Peak

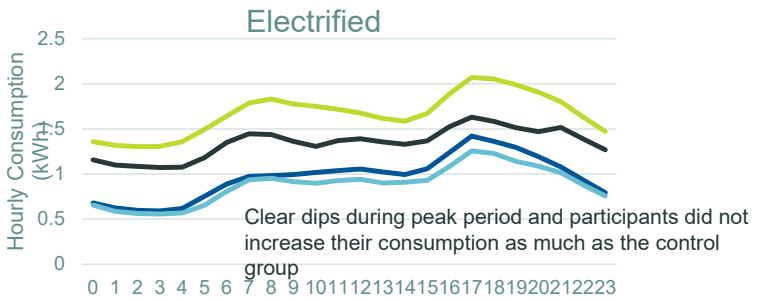
Parameters	Morning Peak				Evening Peak			
	Steady Electric Heating	Electrified	De-electrified	Steady Non-electric	Electric Heating	Electrified	De-electrified	Steady Non-electric
Average Load Reduction During Peak Hours (kW)	0.164 ± 0.036	0.334 ± 0.071	-0.113 ± 0.071	-0.048 ± 0.026	0.185 ± 0.030	0.320 ± 0.068	-0.141 ± 0.067	-0.055 ± 0.028
Average Load – TOU Participants, Pre-Pilot (kW)	2.513	0.926	2.167	0.855	2.557	1.179	2.262	1.100
Relative Average Load Reduction (%)	6.5%	36.1%	-5.1%	-4.7%	7.2%	27.2%	-6.2%	-4.5%

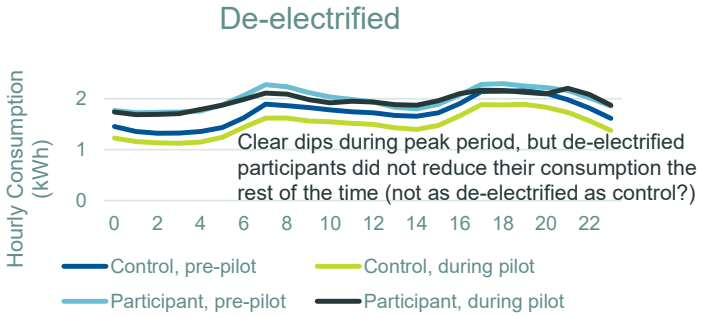
› All savings are statistically significant, but negative for de-electrified and steady non-electric customers. Reason for negative savings is visible in daily loadshapes (next slide)

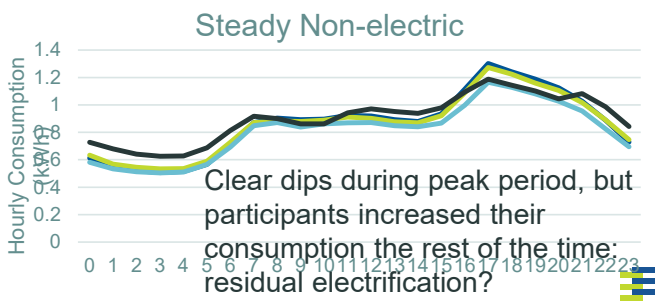
ECONOLER

TOU Impacts – Load During Peak









ECONOLER

TOU Impacts – Energy Usage

Parameters	Steady Electric	Electrified	De-electrified	Steady Non-electric	All
Winter Non-Holiday Weekdays					
Average Daily Electricity Savings (kWh/day)	1.653 ± 0.304	5.702 ± 2.664	-4.795 ± 2.886	-2.456 ± 0.865	1.486 ± 1.216
Average Daily Electricity Consumption, TOU Participants, Pre-Pilot (kWh/day)	54.531	21.148	47.944	19.496	45.330
Relative Daily Electricity Savings (%)	3.0%	27.0%	-10.0%	-12.6%	3.3%
Summer Days					
Average Daily Electricity Savings (kWh/day)	0.410 ± 0.895	-0.395 ± 1.329	1.141 ± 2.059	0.543 ± 0.831	0.665 ± 0.642
Average Daily Electricity Consumption, TOU Participants, Pre-Pilot (kWh/day)	29.640	20.177	27.432	19.932	26.398
Relative Daily Electricity Savings (%)	1.4%	-1.9%	4.2%	2.7%	2.5%

For all TOU participants combined, savings are statistically significant for all days throughout the year and add up to a total of 359 kWh annually on average.

ECONOLER

TOU Bill Impacts

Bill impacts compare participant's old energy consumption patterns with their standard residential tariff to their new energy consumption patterns and TVP tariff.

Parameters	Winter Non-Holiday Weekdays	Winter Weekends and Holidays	Winter Overall	Summer	Annual Average
Average Bill Savings per Day ($/day)	-2.351 ± 0.250	0.232 ± 0.227	-1.501 ± 0.185	1.480 ± 0.103	0.239 ± 0.098
Average Bill per Day – TOU Participants, Pre-Pilot ($/day)			8.038	4.644	6.048
Relative Average Bill Savings (%)			-18.7%	31.9%	4.0%

On average, TOU participants saved $87 annually

ECONOLER

TOU Bill Impacts

Parameters	Steady Electric	Electrified	De-electrified	Steady non-electric
Average Bill Savings per Day ($/day)	0.186 ± 0.112	0.539 ± 0.225	-0.189 ± 0.334	0.107 ± 0.100
Average Bill per Day– TOU Participants, Pre-Pilot ($/day)	7.054	3.647	6.342	3.501
Relative Average Bill Savings (%)	2.6%	14.8%	-2.8%	3.1%

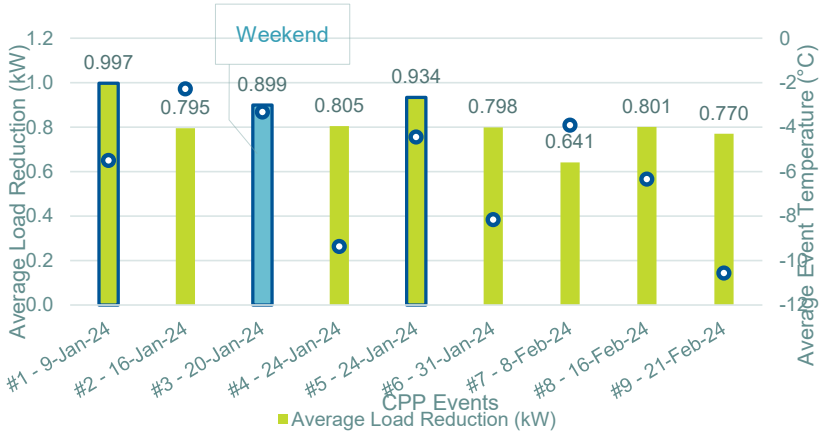
Participants with a de-electrified heating scenario are the only ones that obtain negative bill savings (although not statistically significant) annually. All other space heating scenarios obtain annual savings that range between $39 (steady non-electric) and $197 (electrified).

ECONOLER

CPP Impacts – Load During Peak

Parameters	Morning Events	Evening Events
Average Load Reduction During CPP Events	0.768 ± 0.222	0.943 ± 0.439
Relative Average Load Reduction (%)	27.0%	32.2%

Blue contour = evening event



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CPP Impacts – Load During Peak

Parameters	Morning Events				Evening Events			
	Steady Electric	Electrified	De-electrified	Steady Non-Electric	Steady Electric	Electrified	De-electrified	Steady Non-Electric
Average Load Reduction During CPP Events (kW)	0.871 ± 0.258	0.490 ± 0.565	0.762 ± 0.517	0.311 ± 0.239	1.040 ± 0.512	0.723 ± 1.269	0.961 ± 1.074	0.471 ± 0.645
Average Load - CPP Participants, Reference Days (kW)	3.336	1.508	2.577	0.951	3.367	1.796	2.626	1.224
Relative Average Load Reduction (%)	26.1%	32.5%	29.6%	32.7%	30.9%	40.2%	36.6%	38.5%

- Space heating scenarios have a more limited impact in CPP because reference and event days are both in the post period
- All scenarios see load reduction.

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CPP Impacts – Winter Energy Usage

- Average energy savings on event days compared to reference days: 3.37 ± 3.30 kWh
- Average energy savings compared to the pre-participation year are 476 ± 364 kWh per year

Parameters	Steady Electric	Electrified	De-Electrified	Steady Non-electric
Winter, Non-Holiday Weekdays				
Average Daily Electricity Savings (kWh/day)	2.357 ± 1.854	9.010 ± 4.935	-5.401 ± 3.897	-2.747 ± 1.285
Average Daily Electricity Consumption, CPP Participants, Pre-Pilot (kWh/day)	58.633	21.501	43.761	18.573
Relative Daily Electricity Savings (%)	4.0%	41.9%	-12.3%	-14.8%
Summer Days				
Average Daily Electricity Savings (kWh/day)	1.138 ± 0.998	5.072 ± 3.550	1.413 ± 5.954	0.592 ± 2.495
Average Daily Electricity Consumption, CPP Participants, Pre-Pilot (kWh/day)	30.466	20.993	26.891	20.005
Relative Daily Electricity Savings (%)	3.7%	24.2%	5.3%	3.0%

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CPP Bill Impacts

Parameters	Winter Non-holiday Weekday	Winter Weekends and Holidays	Winter Overall	Summer	Annual Average
Average Bill Savings per Day ($/day)	0.348 ± 0.179	1.300 ± 0.306	0.661 ± 0.157	1.030 ± 0.165	0.876 ± 0.116
Average Bill per Day– CPP Participants, Pre-Pilot ($/day)			8.789	5.139	6.649
Relative Average Bill Savings (%)			7.5%	20.0%	13.2%

On average, CPP participants saved $320 annually

Parameters	Steady Electric	Electrified	De-electrified	Steady Non-electric
Average Bill Savings per Day ($/day)	0.978 ± 0.118	1.676 ± 0.372	0.310 ± 0.612	0.323 ± 0.251
Average Bill per Day – CPP Participants, Pre-Pilot ($/day)	7.434	3.742	5.967	3.447
Relative Average Cost Savings (%)	12.1%	44.8%	5.2%	9.4%

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RESULTS - COMMERCIAL PARTICIPANTS

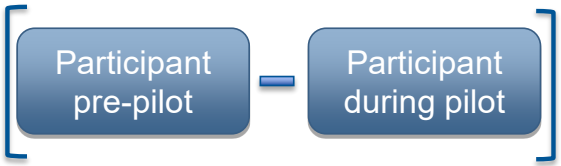
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Overview of Methodology

No control group was available for commercial customers.

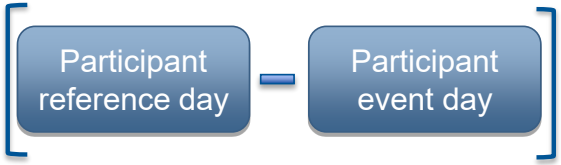
TOU (n=43)

› Energy consumption is normalized to correspond to a normal weather year.



CPP (n=10)

› For each participant-event, a regression is used to adjust the reference day consumption to correspond to the weather of the event day.



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Commercial TVP Yields Inconclusive Results

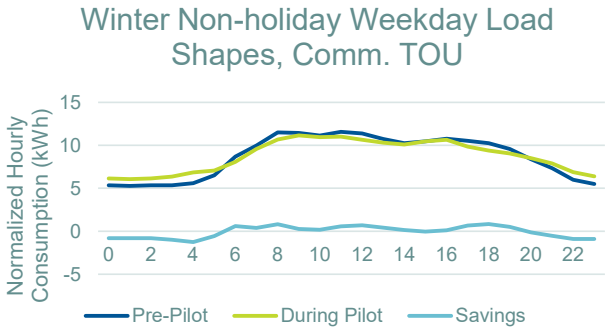
- Savings are not statistically significant for load during peak, energy savings nor billing impacts.
- TOU participants appear to have made small changes to their energy consumption patterns in the morning and evening peak periods, although not in a way that yielded statistically significant load reductions. There was no correlation between the timing of CPP peak events and any visible change in electricity usage levels.

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TOU Impacts

› Savings seem to increase during the peak periods, but are **not statistically significant**

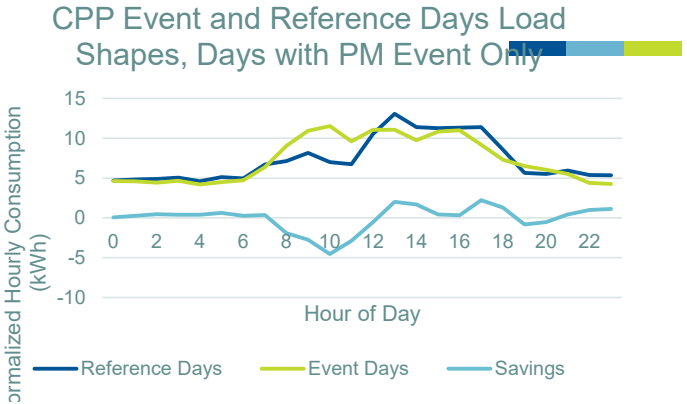
Parameter	Value	Relative value
Average AM peak savings (kW)	0.420 ± 1.393	3.8%
Average PM peak savings (kW)	0.473 ± 1.417	4.9%
Total daily savings (kWh/day)	-1.372 ± 2.969	-0.7%

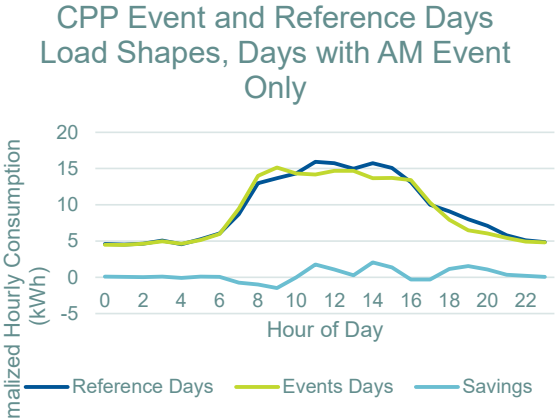


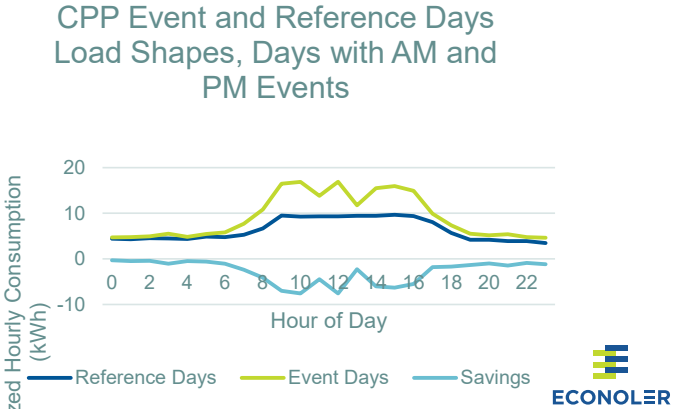
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CPP Impacts

› No correlation between the timing of the event and the times at which hourly savings are positive



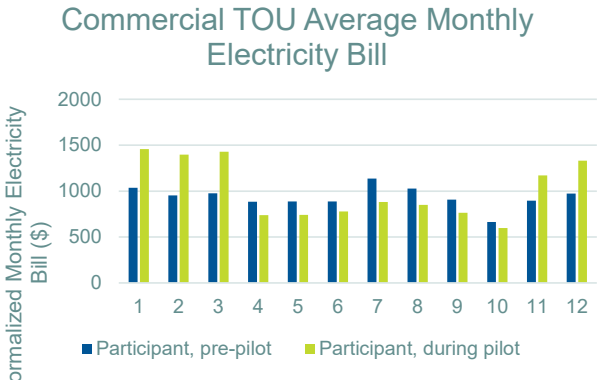


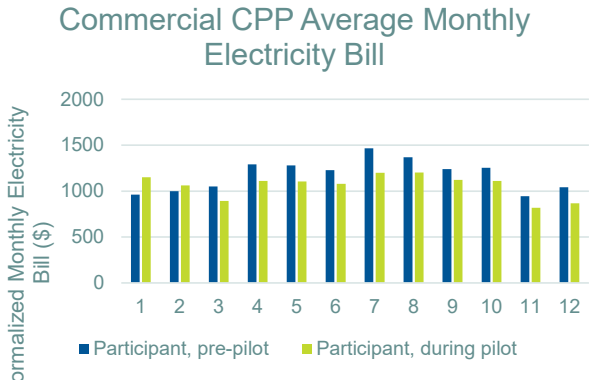


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TOU and CPP Bill Impacts

› Commercial TOU participants saw their bill increase by 8% while CPP participants' bills decreased by 11%. These changes were not statistically significant.





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THANK YOU

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Review of Draft List of Proposed
MURB TOU Tariff Evaluation Metrics
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Draft List of Proposed MURB TOU Tariff Evaluation Metrics

- In its Decision on the 2024/25 Application, the Board directed NS Power:

> To file no later December 31, 2024, a list of the proposed MURB TOU Tariff evaluation metrics, and their definitions, along with an explanation of how it will measure the impact and difference in revenue received under this Tariff, compared to that which would have been received under the General tariff.

- Slides 32 and 33 provide an overview of NS Power's evaluation metrics approach and proposed MURB TOU Pilot Tariff evaluation metrics for review and discussion
- NS Power welcomes input and comments from stakeholders on the proposed metrics
- In accordance with the Board's directive, NS Power will file its list of the proposed MURB TOU Pilot Tariff evaluation metrics before December 31, 2024

MURB TOU Tariff Evaluation Metrics Approach

- Evaluation, measurement and verification (EM&V) plans are roadmaps for maximizing the learnings from pilot or program deployments
  - EM&V plans aim to clearly articulate the goals of the program, identify metrics to be tracked and data requirements, and help evaluators to analyze data and information in a transparent, replicable way
- NS Power proposes to file a single EM&V report by July 31, 2025 which will include the existing six (6) TVP Tariffs (Domestic, Small General, and General CPP and TOU) and the addition of the MURB TOU Pilot Tariff
- NS Power intends to leverage EM&V plan format that was designed with stakeholder consultation prior to the launch of the TVP Rates in 2021 and has been used and refined in the Year 1-3 Evaluation Reports
- The metrics for the MURB Pilot Tariff will include the existing EM&V metrics as seen in the Year 1-3 Evaluation Reports as well as the incorporation of new metrics (as proposed on the next slide) such as revenue impact, and the impact on demand charge to meet Board directive and Consensus Agreement commitments

Proposed MURB Pilot Tariff Evaluation Metrics

Category	Measurement Metric	Definition
Load Impact	Change in load during peak periods (kW)	The average load reduction determined by the regression for winter morning peak, winter evening peak, winter mid-peak and summer on-peak as defined by the Multi-Unit Residential Time-of-Use Tariff.
	Change in load during the highest Adjusted Net Load (ANL) hours	The change in load during the highest 20, 50 and 88 ANL hours during the year will be determined using the regression. The evaluation will include analysis of coincident TOU peak and highest ANL hours
	Change in the average usage levels (kWh)	The average Daily Electricity Savings (kWh/day) and Relative Daily Electricity Savings (%) by season
	Snapback (energy and demand) ***ADDITIONAL***	Average Snapback in kWh occurring in the four hours immediately following the peak period and change in kW 15-minute demand
Billing Impact (measures the impact and difference in revenue received from MURB vs General Tariff)	Change in electricity bills by season	Average Bill Savings per Day ($/day) and Relative Average Bill Savings (%) by season, annual average, and revenue impact of the pilot group.
	Demand charge comparison ***NEW***	Comparison of monthly demand in pre and treatment periods
	Own/daily price elasticity	A measure of the percentage change in average daily electricity usage
	Inter-period substitution elasticity	A measure of the degree to which customers change their electricity consumption across peak, mid peak, and off-peak periods in response to various price signals. Will be measures in kW.


Draft 2024/25 Areas of Focus
Work Plan for Discussion
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Draft 2024/25 Areas of Focus Work Plan (1/5)

- NS Power anticipates three Technical Sessions, expected to occur between February and late-April
- The items in this draft work plan are for review and discussion with stakeholders
- NS Power is seeking feedback and discussion on these items at today's session, and will include a comment period following the session
- NS Power will distribute a revised proposed 2024/25 Areas of Focus Work Plan in January, following stakeholder input, which will include anticipated Technical Sessions and Timelines

Session & Timeline	Summary of 2024/25 Areas of Focus & Board Directives	Type	Items to be Discussed/Reviewed
Kick-off (today)	• Annual TVP development cycle (review of prior year results with stakeholders)	CA	• Year Three Evaluation Report review
	• File list of proposed MURB TOU Pilot Tariff evaluation metrics and definitions by 31 Dec 2024	BD	• Review of draft list of proposed MURB EM&V metrics and definitions in advance of NS Power's filing by 31 Dec 2024
	• Annual TVP development cycle (review of areas of focus work plan)	CA	• Draft 2024/25 Areas of Focus Work Plan review

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CA = commitment from 2024 TVP Consensus Agreement

BD = Board directive (M11822, M11823, or M11621)

Draft 2024/25 Areas of Focus Work Plan (2/5)

Session & Timeline	Summary of 2024/25 Areas of Focus & Board Directives	Type	Items to be Discussed/Reviewed
TBD following stakeholder feedback & input (revised work plan will be distributed in January 2025)	**1.0 – Demand Charges** • (1.1) evaluate the extent to which the demand charge may act as a barrier to General class TOU participation and continue to evaluate non-demand TVP designs for General Service customers • (1.2) assessment of demand charge impacts on General Service customers and evaluation of demand charge modifications or alternatives for TVP offerings to General Service customers • (1.3) evaluate the level of costs that are truly driven by an individual's non-coincident demands (e.g. an individual customer's transformer), and only recover those costs through a non-coincident demand charge. All other demand-related costs should be recovered through either an on-peak volumetric charge or a demand charge that only applies during on-peak hours • (1.4) complete a performance assessment of the General Service Class customers, as described in Synapse's evidence, evaluating the extent that bills increase as they shift load from on-peak hours to off-peak hours. It is expected that this assessment will identify whether the demand charge increases the electricity bills for these participants. If the assessment finds that the demand charge results in higher bills to the commercial class customers shifting their load from on-peak to off-peak, NS Power is to assess removal of the demand charge, as well as any other changes, which could incentivize the participation of the commercial rate class customers in the TVP Program.	BD	• Prepare summary of how demand charges are currently implemented and billed, for instance: demand charge, first energy block. • Comparison of pricing demand in TVP versus standard offer tariffs • Examine availability of data and cost drivers to determine individual customer cost impacts and potential of TVP to influence • Discussion of scoping in relation to item 1.3 • Identify impact load shifting may have on demand charges for existing General rate customers (through performance assessment) and examination of alternative demand applications • Compile sample data using AMI meters to review correlation of General customers' demand to system peaks

Draft 2024/25 Areas of Focus Work Plan (3/5)

Session & Timeline	Summary of 2024/25 Areas of Focus & Board Directives	Type	Items to be Discussed/Reviewed
TBD following stakeholder feedback & input (revised work plan will be distributed in January 2025)	**2.0 – Potential Tariff Changes / Introductions** • (2.1) identify potential tariff changes which could improve customer participation in the TVP program, load shifting and alignment with the highest cost hours	BD	• Examine customers' correlation with system peaks by rate class • Discuss the trade offs with a seasonally neutral TVP rate relative to the standard rate to allow year-round enrolment. This could remove a barrier to higher participation at the trade off a potentially of lower correlation to system costs. • Undertake development and assessment of a rate including both Saturday and/or Sunday on the targeted rate class and the impact on potential TOU rates and the broader TVP development strategy • Review the opportunities and restrictions with batteries today on current TVP rates and general demand rates when paired with consumption and develop recommendations to address, as appropriate. • Identify and evaluate additional potential use cases of behind-the-meter energy storage in the context of TVP pricing ratios (e.g. 2:1, 10:1) and net metering
	• (2.2) Board directive from SGNS Final Report (M11621) – discussion of new and/or revised tariffs enabling customers to have the option to charge from, and discharge to, the grid with behind-the-meter energy storage (including vehicle-to-grid) that is not integrated with generation	BD	
	• (2.3) examination of alternative Domestic tariffs including a TOU structure with weekend peak/off-peak periods	CA	
	• (2.4) provide a draft weekend-inclusive TOU tariff to be reviewed by stakeholders in the upcoming engagement sessions	BD	
	3.0 – Accessibility of TVP • (3.1) Review of accessibility as applicable to vulnerable customers (i.e. low-income)	CA	• Examine the results of the Year 3 report as it relates to income and develop proposal to address gaps/opportunities , as appropriate • Assess potential impacts to vulnerable customers • Examination of challenges with more detailed income analyses (e.g. lack of control group)

Draft 2024/25 Areas of Focus Work Plan (4/5)

Session & Timeline	Summary of 2024/25 Areas of Focus & Board Directives	Type	Items to be Discussed/Reviewed
TBD following stakeholder feedback & input (revised work plan will be distributed in January 2025)	**4.0 – Review of Current Tariffs, Mechanisms & Capabilities** • (4.1) exploration of TVP revenue stability mechanisms	CA	• Any MURB rate adjustments will be proposed to the stakeholder's group once data has been acquired from the pilot and analyzed. • Continuous refinements are made annually on the TVP load reduction methodology. NS Power understands that the TVP results by space heating classification did not provide tangible results, this methodology will be reviewed by NS Power in consultation with Econoler; findings will be presented. Comments / direction on this matter from stakeholders are welcome • Provide update on status of current metering and CIS system capabilities and future potential capabilities with system upgrade and plan to address in TVP strategy. • Provide an assessment of revenue impacts and potential tools available to address as required (e.g. enrolment targets, rate design scorecard) • Review of marketing and communication efforts for 2024/25 recruitment
	• (4.2) MURB TOU Pilot Tariff should continue to be refined to better reflect the value of load shifting by considering marginal costs (or avoided costs) in determining the rates in each period	BD	
	• (4.3) work with stakeholders to refine its methods of estimating load reductions achieved through the TVP tariffs	BD	
	• (4.4) review of current metering and billing (Customer Information System) system capabilities	CA	
	5.0 – Reporting on Small Business Customer Items • (5.1) report to stakeholders on changes that could be made to help customers determine whether they will benefit from TVP	CA	• Analysis of general load characteristics of small business customers that may shift load in response to TVP • Information on commercial/small business customer recruitment small business customer outreach. • Explore opportunities that could allow customers to be classified by business sector and provide an update on these efforts • Summary of specific reasons why customers are reluctant to participate, followed by an evaluation of the pilot tariff to see if changes can address some of the concerns

Draft 2024/25 Areas of Focus Work Plan (5/5)

Session & Timeline	Summary of 2024/25 Areas of Focus & Board Directives	Type	Items to be Discussed/Reviewed
TBD following stakeholder feedback & input (revised work plan will be distributed in January 2025)	**6.0 – Review of System Planning Related Values** • (6.1) review of system planning related values as applicable to TVP (and the technologies that deliver the load shifting such as batteries) including avoided costs and Effective Load Carrying Capability (ELCC)	CA	Review system planning related value applicable to TVP including: • Technologies that deliver load shifting • Update on the avoided cost analysis from 2023/24 (Year Three) Technical Sessions, how the avoided costs were applied to TVP, and rate design scorecard to discuss the assessment of TVP cost reflectivity • Examine alignment of TVP pricing with avoided cost and determine implications for future TVP pricing • Review of ELCC as applied to TVP • Review and establish the parameters for the analysis of system margin and CPP events to be provided in the Year 4 Report
	• (6.2) discuss an assessment of the degree to which the TVP offering reflect avoided costs, with the potential for modifications to the tariffs to ensure that they are cost-reflective	BD	
	• (6.3) discuss an analysis of the correspondence of system margin forecasts and CPP events in the Year 4 report, providing the days with a forecast of low system margin and the forecast system margin for the days when a CPP event was called	BD	

Other Board Directives for 2024/25

As part of the Board's Decision in M11822 (2024/25 TVP Application), NS Power will also:

- Report on the Year Four findings and file the annual EM&V Report no later than 31 Jul 2025

As part of the Board's Decision in M11823 (Year Three Evaluation Report), NS Power will, in its Year Four Report:

- provide an analysis of the correspondence of system margin forecasts and CPP events, providing the days with a forecast of low system margin and the forecast system margin for the days when a CPP event was called
- report on the review of its marketing and communication efforts and its planned changes, informed by stakeholders through the pricing innovation process
- provide the outcome of the performance assessment (item 1.5 on the draft work plan) of the General Service Class customers, as described in Synapse's evidence, and potential tariff changes to stakeholders during an engagement session
    - if it is determined the demand charge is not a deterrent and/or the cause of lower commercial customer enrollment, NS Power will review and improve its customer engagement with commercial rate class customers and to revisit the incentive structure for the commercial TVP tariffs so that commercial operations and load shifting are not mutually exclusive

Other Consensus Agreement Items for 2024/25

As part of its Year Four Report, NS Power will:

- Following the completion of the Year 4 pilot, NS Power will develop and provide to stakeholders an examination of the commercial class customer characteristics (load shape, magnitude, business type) that have demonstrated the capacity in the TVP pilot to reduce load during peak periods. Findings may enable targeted outreach to non-TVP pilot small business customers with similar characteristics, with the intent to improve enrolment and response to CPP and/or TOU peak periods
- Maintain the established TVP Report and EM&V processes
- File an annual EM&V report that will be prepared internally by NS Power
- Conduct a MURB Industry Group Session, which may include discussion on the following:
    - Based on feedback received from MURB stakeholders, the parties acknowledge that incentives and rebates from third parties are expected to be required to support the adoption of TVP rates by MURB customers and the parties will support the development and introduction of such opportunities



Near Term Next Steps

- Fri, 22 Nov – NS Power circulated slides
- Today (Wed, 27 Nov) – Kick-off TVP Development Cycle (2024/25) Session
- Thu, 12 Dec – stakeholders provide comments on draft 2024/25 Areas of Focus Work Plan and the proposed list of MURB TOU Tariff evaluation metrics to NS Power
- By Tue, 31 Dec – NS Power file its proposed list of MURB TOU Pilot Tariff evaluation metrics
- January 2025 – NS Power distribute revised 2024/25 Areas of Focus Work Plan and schedule Technical Session 1 (for February 2025)

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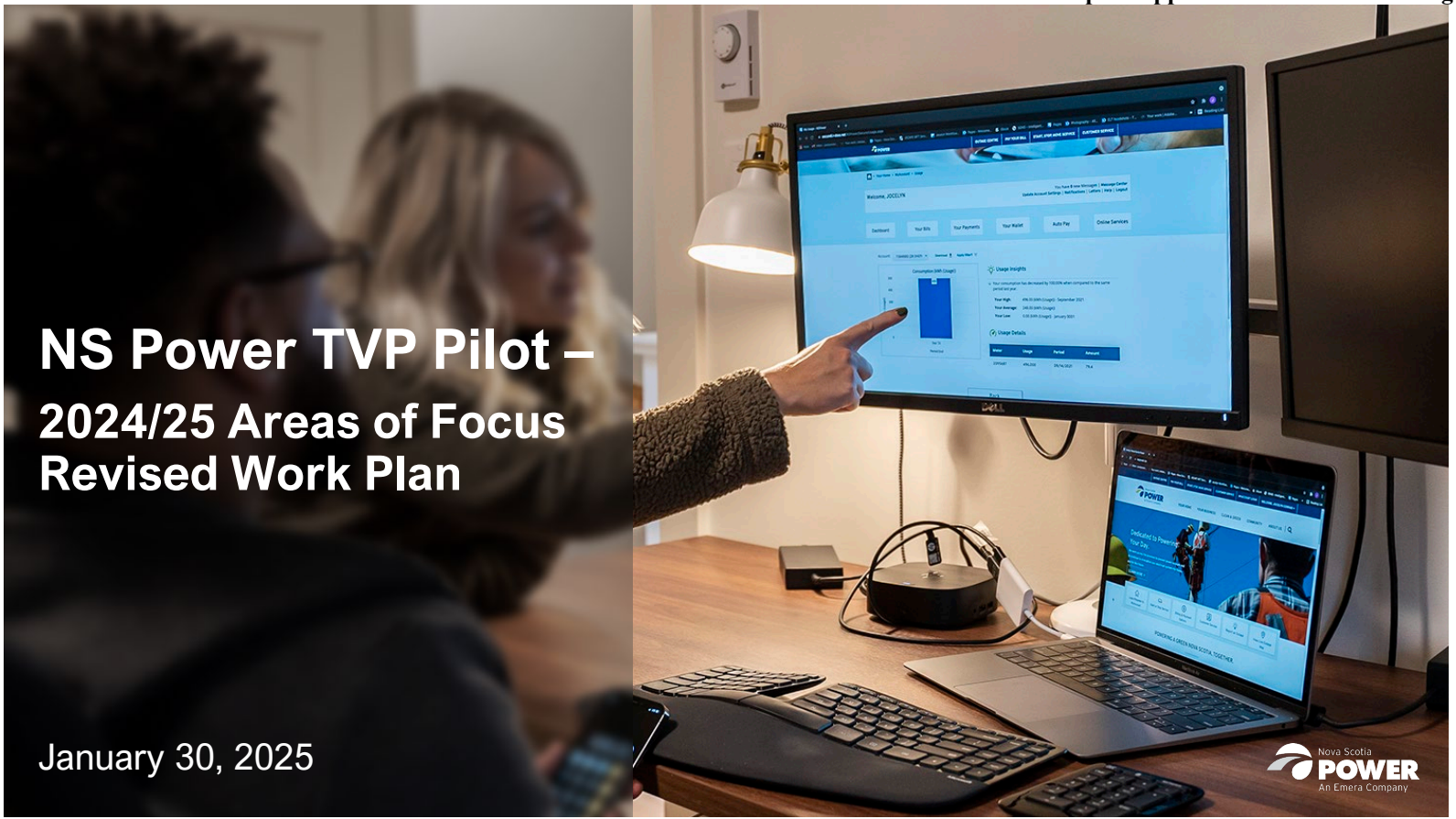

Appendix
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Rate Design Scorecard Rubric

Item	Objective	0 - Does Not Meet Objectives	1 - Meets Some Objectives	2 - Meets Most Objectives	3 - Meets All Objectives
Customer Orientation	The Tariff should be oriented to customers, maintaining simplicity while providing customer choices *Normalization Note* *Change from Base ≥ 10%* *a) Off-Peak: +/- 1 point* *b) Peak: +/- 1 point*	Tariff does not meet any of the 3 criteria: (1) easy to understand, (2) has attractive pricing differentials, and (3) provides customers with rate choice.	Tariff meets one of 3 criteria: (1) easy to understand, (2) has attractive pricing differentials, and (3) provides customers with rate choice.	Tariff meets two of 3 criteria: (1) easy to understand, (2) has attractive pricing differentials, and (3) provides customers with rate choice.	Tariff meets all 3 criteria: (1) easy to understand, (2) has attractive pricing differentials, and (3) provides customers with rate choice.
	The Tariff has demonstrated customer interest	<50% of Enrolment Target is met OR <10% of Customers Surveyed indicate interest	50-74.9% of Enrolment Target is OR ≥10% of Customers Surveyed indicate interest	75-99.9% of Enrolment Target is met OR ≥30% of Customers Surveyed indicate interest	100% of Enrolment Target is met OR ≥50% of Customers Surveyed indicate interest
Encourage Efficient Operations ***Informed by IRP and internal undertakings***	The Tariff should encourage system efficiency gains through load shifting potential and peak periods aligned with system peak and cost of service	<50% of peak periods are aligned with system peak	50-75% of peak periods are aligned with system peak	75-90% of peak periods are aligned with system peak	≥90% of peak periods are aligned with system peak
Fair Value	Customers load shift should be reflected in bill savings	No significant difference between customer load shift and structural savings (<1%)	Load shift customer savings exceed structural customer savings by ≥1%	Load shift customer savings exceed structural customer savings by ≥5%	Load shift customer savings exceeds structural customer savings by ≥10%
	Customers should experience annual savings compared to the standard offer rate	No annual load shift savings (<1%)	Annual load shift savings ≥1%	Annual load shift savings ≥5%	Annual load shift savings ≥10%
	Tariff volumetric rates correlate to marginal cost of electricity (i.e. largely fuel)	Volumetric rates do not reflect marginal cost of electricity. No correlation. Correlation coefficient < 0.1	Weak statistically significant correlation. Correlation coefficient ≥ 0.1	Statistically significant correlation. Correlation coefficient ≥ 0.2	Strong statistically significant correlation. Correlation coefficient ≥ 0.4
Accessibility	The Tariff should remain affordable and accessible to vulnerable sub populations	Tariff is not affordable or accessible to vulnerable sub populations	Tariff is affordable and accessible to vulnerable sub populations with many exceptions	Tariff is affordable and accessible to vulnerable sub populations with a few exceptions	Tariff is affordable and accessible to vulnerable sub populations
Customer Equality	The Tariff should aspire for a balance of 50/50 Structural Winners and Structural Losers.	Under 10% are either Structural Winners or Losers	Tariff achieves balance +/- 30% (i.e. Structural Winners 20-80%)	Tariff achieves balance +/- 20% (i.e. Structural Winners 30-70%)	Tariff achieves balance +/- 10% (i.e. Structural Winners 40-60%)
Revenue Neutrality	The Tariff should be revenue neutral without recognition of the value of load shifting for fairness across the rate class	Structural analysis indicates average bill change greater than +/- 10%	Structural analysis indicates average bill change less than +/- 10%	Structural analysis indicates average bill change less than +/- 5%	Structural analysis indicates average bill change less than +/- 1%

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As presented in 2023/24 Stakeholder Engagement Session 4 on June 26, 2024



NS Power TVP Pilot –
2024/25 Areas of Focus
Revised Work Plan

January 30, 2025

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Introduction

- On November 27, 2024, NS Power held a TVP session to formally kick off the 2024/25 TVP engagements
  - Included on the agenda were a review of the Year Three Evaluation Report results, the proposed list of multi-unit residential building (MURB) Time-of-Use (TOU) Pilot Tariff metrics, and the draft 2024/25 Areas of Focus Work Plan for discussion and feedback from stakeholders
- In December 2024, NS Power received comments from the Consumer Advocate (CA) and Energy Storage Canada on the November 27, 2024 Kick-off Session – responses are provided as Attachment A
- Revisions to the draft 2024/25 Areas of Focus Work Plan, incorporating comments from the CA and ESC are provided in these slides
  - The items in this revised work plan are for review and discussion with stakeholders
- NS Power anticipates three Technical Sessions, the first will be scheduled in February 2025 and the other two to occur between March and late-April

TVP Tariff Development Cycle

- As provided in the 2024 TVP Consensus Agreement – the Company will continue to manage and refine its TVP Program in a structured, analytics-based, and stakeholder engaged manner focusing on an annual TVP development, approval and implementation cycle including, for each year:

November	Winter/Spring	Spring/Summer	Summer/Autumn
• Effective date for TVP tariff changes • Enrolment cut-off for coming winter period	• Data collection and monitoring of TVP program performance • Development of program refinements	• Measurement, evaluation, and reporting on TVP Tariff results • Presentation and application for approval of changes to TVP tariffs	• Marketing and recruitment of TVP customers

- Across this annual cycle the Company will maintain ongoing stakeholder engagement such that stakeholders are provided with the information required to remain informed of the TVP Program progress and prepared to provide input on the TVP Program strategy and proposed changes to the TVP Tariff offerings


2024/25 Areas of Focus
Revised Work Plan
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2024/25 Areas of Focus – Revised Work Plan (1/5)

Technical Session 1 – to be scheduled (week of 24 February 2025)

Summary of 2024/25 Areas of Focus & Board Directives	Type	Items to be Discussed/Reviewed
1.0 – Accessibility of TVP • (1.1) Review of accessibility as applicable to vulnerable customers (i.e. low-income)	CA	• Examine the results of the Year 3 report as it relates to income and develop proposal to address gaps/opportunities , as appropriate • Assess potential impacts to vulnerable customers • Examination of challenges with more detailed income analyses (e.g. lack of control group) • **NEW** – in response to the Consumer Advocate's comments, NS Power will provide a summary of applicant characteristics (e.g. customer home type, primary heating source) for review and discussion re. barriers to accessing TVP Tariffs for renters v. homeowners
2.0 – Review of Current Tariffs, Mechanisms & Capabilities • (2.1) exploration of TVP revenue stability mechanisms	CA	• **NEW** – TVP revenue stability will be explored using the structural and load shift revenue neutrality models and/or avoided cost models. • **REVISED** – Any MURB rate adjustments or refinements will be proposed to the stakeholder's group once sufficient data is available and analysis has been completed. • Continuous refinements are made annually on the TVP load reduction methodology. NS Power understands that the TVP results by space heating classification did not provide tangible results, this methodology will be reviewed by NS Power in consultation with Econoler; findings will be presented. Comments / direction on this matter from stakeholders are welcome • Provide update on status of current metering and CIS system capabilities and future potential capabilities with system upgrade and plan to address in TVP strategy. • Provide an assessment of revenue impacts and potential tools available to address as required (e.g. enrolment targets, rate design scorecard) • Review of marketing and communication efforts for 2024/25 recruitment
• (2.2) MURB TOU Pilot Tariff should continue to be refined to better reflect the value of load shifting by considering marginal costs (or avoided costs) in determining the rates in each period	BD	
• (2.3) work with stakeholders to refine its methods of estimating load reductions achieved through the TVP tariffs	BD	
• (2.4) review of current metering and billing (Customer Information System) system capabilities	CA	

2024/25 Areas of Focus – Revised Work Plan (2/5)

Technical Session 2 – anticipated mid-March

Summary of 2024/25 Areas of Focus & Board Directives	Type	Items to be Discussed/Reviewed
3.0 – Demand Charges • (3.1) evaluate the extent to which the demand charge may act as a barrier to General class TOU participation and continue to evaluate non-demand TVP designs for General Service customers • (3.2) assessment of demand charge impacts on General Service customers and evaluation of demand charge modifications or alternatives for TVP offerings to General Service customers • (3.3) evaluate the level of costs that are truly driven by an individual's non-coincident demands (e.g. an individual customer's transformer), and only recover those costs through a non-coincident demand charge. All other demand-related costs should be recovered through either an on-peak volumetric charge or a demand charge that only applies during on-peak hours • (3.4) complete a performance assessment of the General Service Class customers, as described in Synapse's evidence, evaluating the extent that bills increase as they shift load from on-peak hours to off-peak hours. It is expected that this assessment will identify whether the demand charge increases the electricity bills for these participants. If the assessment finds that the demand charge results in higher bills to the commercial class customers shifting their load from on-peak to off-peak, NS Power is to assess removal of the demand charge, as well as any other changes, which could incentivize the participation of the commercial rate class customers in the TVP Program.	BD	• Prepare summary of how demand charges are currently implemented and billed, for instance: demand charge, first energy block. • Comparison of pricing demand in TVP versus standard offer tariffs • Examine availability of data and cost drivers to determine individual customer cost impacts and potential of TVP to influence • Discussion of scoping in relation to item 3.3 • Identify impact load shifting may have on demand charges for existing General rate customers (through performance assessment) and examination of alternative demand applications • Compile sample data using AMI meters to review correlation of General customers' demands to system peaks

2024/25 Areas of Focus – Revised Work Plan (3/5)

Technical Session 2 (continued) – anticipated mid-March

Summary of 2024/25 Areas of Focus & Board Directives	Type	Items to be Discussed/Reviewed
4.0 – Reporting on Small Business Customer Items • (4.1) report to stakeholders on changes that could be made to help customers determine whether they will benefit from TVP	CA	• Analysis of general load characteristics of small business customers that may shift load in response to TVP • Information on commercial/small business customer recruitment and customer outreach. • Explore opportunities that could allow customers to be classified by business sector and provide an update on these efforts • Summary of specific reasons why customers are reluctant to participate, followed by an evaluation of the pilot tariff to see if changes can address some of the concerns

2024/25 Areas of Focus – Revised Work Plan (4/5)

Technical Session 3 – anticipated late-April

Summary of 2024/25 Areas of Focus & Board Directives	Type	Items to be Discussed/Reviewed
5.0 – Potential Tariff Changes / Introductions • (5.1) identify potential tariff changes which could improve customer participation in the TVP program, load shifting and alignment with the highest cost hours	BD	• Examine customers' correlation with system peaks by rate class • Discuss the tradeoffs with a seasonally neutral TVP rate relative to the standard rate to allow year-round enrolment. This could remove a barrier to higher participation at the trade of off a potentially lower correlation to system costs. • **NEW** – in response to Synapse's comments, in the TVP 2024/25 Kick-off Session in November 2024, on what a potential structure for a seasonally adjusted default rate might look like. NS Power will provide a reference rate with only a seasonal adjustment. NS Power does not intend to pursue such a rate other then as an informational tool on seasonal impacts for stakeholders. • Undertake development and assessment of a rate including both Saturday and/or Sunday on the targeted rate class and the impact on potential TOU rates and the broader TVP development strategy • Review the opportunities and restrictions with batteries today on current TVP rates and general demand rates when paired with consumption and develop recommendations to address, as appropriate. • Identify and evaluate additional potential use cases of behind-the-meter energy storage in the context of TVP pricing ratios (e.g. 2:1, 10:1) and net metering.
• (5.2) Board directive from SGNS Final Report (M11621) – discussion of new and/or revised tariffs enabling customers to have the option to charge from, and discharge to, the grid with behind-the-meter energy storage (including vehicle-to-grid) that is not integrated with generation	BD	
• (5.3) examination of alternative Domestic tariffs including a TOU structure with weekend peak/off-peak periods	CA	
• (5.4) provide a draft weekend-inclusive TOU tariff to be reviewed by stakeholders in the upcoming engagement sessions	BD	

2024/25 Areas of Focus – Revised Work Plan (5/5)

Technical Session 3 (continued) – anticipated late-April

Summary of 2024/25 Areas of Focus & Board Directives	Type	Items to be Discussed/Reviewed

6.0 – Review of System Planning Related Values
• (6.1) review of system planning related values as applicable to TVP (and the technologies that deliver the load shifting such as batteries) including avoided costs and Effective Load Carrying Capability (ELCC)
	CA	Review system planning related value applicable to TVP including:
		• Technologies that deliver load shifting
		• Update on the avoided cost analysis from 2023/24 (Year Three) Technical Sessions, how the avoided costs were applied to TVP, and rate design scorecard to discuss the assessment of TVP cost reflectivity
		• Examine alignment of TVP pricing with avoided cost and determine implications for future TVP pricing
		• Review of ELCC as applied to TVP
		• Review and establish the parameters for the analysis of system margin and CPP events to be provided in the Year 4 Report
		• **NEW** – in response to the Energy Storage Canada comments, NS Power will:
		  ○ Discuss why NS Power still views the winter evening peak to be the most likely and impactful time for a system peak moving forward. Variability in weather systems can affect timing of system peaks. This creates the potential for system peak to occur at other times such as the morning or weekend daily peaks.
		  ○ What role TVP can play in meeting load and reserve requirements. Both though demand side flexibility, as well as by reducing variability in daily load.

• (6.2) discuss an assessment of the degree to which the TVP offering reflects avoided costs, with the potential for modifications to the tariffs to ensure that they are cost-reflective	BD	
• (6.3) discuss an analysis of the correspondence of system margin forecasts and CPP events in the Year 4 report, providing the days with a forecast of low system margin and the forecast system margin for the days when a CPP event was called	BD	



Near Term Next Steps

- Thu, 30 Jan 2025 – NS Power distribution of revised 2024/25 Areas of Focus Work Plan and Responses to Comments (Attachment A)
- (to be scheduled) week of 24 Feb 2025 – Technical Session 1
- (to be scheduled) week of 10 Mar 2025 – Comments to NS Power on Technical Session 1


Appendix
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Other Board Directives for 2024/25

As part of the Board's Decision in M11822 (2024/25 TVP Application), NS Power will also:

- Report on the Year Four findings and file the annual EM&V Report no later than 31 Jul 2025

As part of the Board's Decision in M11823 (Year Three Evaluation Report), NS Power will, in its Year Four Report:

- Provide an analysis of the correspondence of system margin forecasts and CPP events, providing the days with a forecast of low system margin and the forecast system margin for the days when a CPP event was called
- Report on the review of its marketing and communication efforts and its planned changes, informed by stakeholders through the pricing innovation process
- Provide the outcome of the performance assessment (item 1.5 on the draft work plan) of the General Service Class customers, as described in Synapse's evidence, and potential tariff changes to stakeholders during an engagement session
    - If it is determined the demand charge is not a deterrent and/or the cause of lower commercial customer enrollment, NS Power will review and improve its customer engagement with commercial rate class customers and revisit the incentive structure for the commercial TVP tariffs so that commercial operations and load shifting are not mutually exclusive

Other Consensus Agreement Items for 2024/25

As part of its Year Four Report, NS Power will:

- Following the completion of the Year 4 pilot, NS Power will develop and provide to stakeholders an examination of the commercial class customer characteristics (load shape, magnitude, business type) that have demonstrated the capacity in the TVP pilot to reduce load during peak periods. Findings may enable targeted outreach to non-TVP pilot small business customers with similar characteristics, with the intent to improve enrolment and response to CPP and/or TOU peak periods
- Maintain the established TVP Report and EM&V processes
- File an annual EM&V report that will be prepared internally by NS Power
- Conduct a MURB Industry Group Session, which may include discussion on the following:
    - Based on feedback received from MURB stakeholders, the parties acknowledge that incentives and rebates from third parties are expected to be required to support the adoption of TVP rates by MURB customers and the parties will support the development and introduction of such opportunities

TIME-VARYING PRICING TARIFF PROGRAM
NS POWER RESPONSES TO STAKEHOLDER COMMENTS

TVP Session	Year Three Review & 2024/25 Kick-off – held 27 November 2024
Comments Received	December 2024
Responses Circulated	January 30, 2025

Stakeholder	Comment	NS Power Response
Consumer Advocate (CA)	Results Reported for Year Three • suggests that in future evaluation reports NSP restate the initial objective or objectives which prompted the initiation of the TVP rate offerings (for instance, reductions in peak energy usage, bill savings for customers, enabling customer choice). • suggests that NSP provide summary comments regarding the extent to which these objectives are met through the program. Providing this evaluative summary regarding whether the pilot program is meeting its intended objective or objectives would enhance the ability of stakeholders to assess the program's successes and areas for potential growth. • notes that for results summaries on slides 15-23 of NSP's PowerPoint presented on November 27, 2024, it would be helpful to show the number of participants in each of the steady electric, electrified, de-electrified, steady non-electric categories.	• NS Power appreciates the suggestions provided by the CA and plans to incorporate the initial objectives and the extent to which these are met in its Year Four Evaluation Report. • The Company agrees that the number of participants is helpful to understanding the data. Please refer to Table 6 in Appendix A to the TVP Year Three Report (M11823) for the number of participants included in each of the electric/non-electric categories. Tables 7 and 18 in Appendix A to the TVP Year Three Report further break this data down by cohort to understand the variances each cohort can have on the results.
	Questions regarding the resulted report for Year Three • Has NSP investigated why the steady electric and electrified category customers seem to have more energy and bill savings? Is one possible explanation that heating loads are significant enough to result in measurable bill savings when they are managed? Could work on this topic be included in the 2024/25 areas of focus work plan?	• Steady electric and electrified customers are isolated for their heating type to be the only fixed variable between them. As a result, we expect the differences in load shift to be attributable to their heating type and ability to shift heating load. NS Power intends to place a focus on these customers in all TVP work in the residential area in 2024/25 including, but not limited to, their correlation to system peak which is planned for discussion at Technical Session 3. • Critical Peak Pricing (CPP) participants do see greater annual savings partly due to the higher load shift observed by CPP participants. It is possible that the

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TIME-VARYING PRICING TARIFF PROGRAM
NS POWER RESPONSES TO STAKEHOLDER COMMENTS

Stakeholder	Comment	NS Power Response
Consumer Advocate (CA)	• Has NSP investigated why the CPP program participants see greater annual savings (slide 23) than TOU participants (slide 18)? Is one possible explanation for this the higher premium on energy use in peak periods in the CPP program? Could work on this topic be included in the 2024/25 areas of focus work plan? • With regard to the comment on slide 14 about "a good proportion of that decrease in performance is due to the difference in space heating scenario mix", the Consumer Advocate asks if this refers to customers: o Moving between the categories (steady, electric heating, electrified, de-electrified), o Or that new enrollments in year-3 are distributed across the categories differently compared to previous years, o Or some other explanation?	higher premium on energy use in peak periods is the cause of this behaviour. When surveyed regarding behaviours customers are likely to do since joining the Pilot, results show that Time-of-Use (TOU) participants are significantly more likely to change behaviours related to their washing machine and dishwasher, while CPP participants are more likely to change when they heat and light up their home as a result of the program[1]. Giving customers a choice of programs with a variety of price signals allows the customers to self select into the program that works for them and the amount of energy they are willing to shift and frequency they are willing to shift that energy. Year 3 enrolments are distributed across the categories differently compared to previous years. Please refer to Table 7 in Appendix A of the Year Three Report (M11823) which shows the participant mix of each cohort by year enrolled and heating type. The increasing numbers of de-electrified customers and decreasing number of electrified customers are of note for TOU and their impact to the average peak reductions. The mix and rate of change within electrified and de- electrified for customers on TVP is an item we intend to review and track on a go forward basis as we refine the heating segmentation model.
	2024/25 Areas of Focus Work Plan Has NSP undertaken a jurisdictional review of time varying rate programs in the United States and Canada to understand challenges and opportunities related to the design and uptake of these programs? If not, could NS Power consider undertaking to do this, including providing information on lessons learned from the experiences of other jurisdictions that could inform future rate design options?[2]	• In 2020, NS Power engaged the Brattle Group to conduct a TVP Jurisdictional Scan of Residential and Commercial pricing options, lessons learned, and recommendations for moving forward. This was provided as Appendix 2 to the Company's TVP Pilot Submission(M09777). • In 2024, NS Power engaged the Brattle Group to conduct an updated Jurisdictional Scan of the Commercial sector which was reviewed with stakeholders at the third Technical Session in May 2024 and filed as Appendix C, Attachment 6 (pages 13-23) to the 2024/25 TVP Application (M11822). • NS Power appreciates the CA sharing the link to BC Hydro's recent jurisdictional scan. NS Power has reviewed this material and notes Brattle Group's

[1] M11823 TVP Pilot Program – Year Three Report Appendix B Page 52 of 65
[2] For an example of such a jurisdictional scan see Appendix F to BC Hydro's 2024 Rate Design Application, doc_77681_b-1-1-bch-2024-ratedesign-appendices.pdf

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TIME-VARYING PRICING TARIFF PROGRAM
NS POWER RESPONSES TO STAKEHOLDER COMMENTS

Stakeholder	Comment	NS Power Response
		jurisdictional scan (in Appendix F of BC Hydro's 2024 Rate Design Application) lists NS Power in its review of residential TVP tariff offerings by utility. Further, it provides a recent (February 2024) and comprehensive overview of North American utility offerings and rate options. The Company finds this informative report a useful guide; however, given it is a recent assessment of residential TVP tariff offerings (inclusive of NS Power's TVP program) across the US and Canada, the Company has not included plans to undertake a similar scan as part of the 2024/25 Areas of Focus Work Plan.
Consumer Advocate (CA)	<u>2024/25 Areas of Focus Work Plan – Potential Tariff Changes</u> • With regard to potential tariff changes discussed in the draft work plan, the Consumer Advocate wonders whether NSP considered combining and cross marketing the Efficiency Nova Scotia Eco Shift Demand Response program with TOU/CPP rate offerings? The Consumer Advocate suggests that this be considered as part of the 2024/25 work plan. • The Consumer Advocate also asks whether NSP has considered offering Demand Response options such as those offered to commercial customers of BC Hydro?[3] If not, the Consumer Advocate requests that this also be considered as part of the 2024/2025 work plan.	• For the 2024/25 season, Efficiency Nova Scotia's Eco Shift Demand Response (DR) Program expanded enrolment to TOU and CPP Tariff participants to assess overlap and to determine how the two programs can work together efficiently. NS Power and EfficiencyOne (E1) will be monitoring this year before deciding whether cross-program enrolment should continue for future years. Both Eco Shift and TOU/CPP Tariffs are pilot programs, so components of the programs can change. The marketing timelines of both pilot programs differ, and both NS Power and E1's marketing teams are working collaboratively to grow cross-promotional efforts more holistically. • NS Power has explored various DR options and continues to work closely with E1 on the development and implementation of DR initiatives. As part of the Smart Grid Nova Scotia project, NS Power and E1 collaborated on deploying advanced building management systems (BMS) for C&I facilities. This initiative demonstrated the potential of smart grid technologies to enhance energy efficiency and reliability. • NS Power's primary role in DR is centered around rates and tariffs. The Company is actively assessing its TVP rate structures to encourage customers to shift and/or shave peak loads, contributing to a more stable and efficient grid. As the DSM Administrator in the province, E1 leads the efforts on DR Program initiative, focusing on optimizing energy usage and reducing

[3] BC Hydro, Demand Response for Business, https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/power-smart/business/programs/demand-response-for-business-customer-manual.pdf

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TIME-VARYING PRICING TARIFF PROGRAM
NS POWER RESPONSES TO STAKEHOLDER COMMENTS

Stakeholder	Comment	NS Power Response
		peak demand for commercial and industrial (C&I) customers. These efforts are akin to BC Hydro's DR programs, which incentivize businesses to shift their electricity use during peak periods. • The Company notes E1 is in the process of assessing its DR Program for the 2026-2030 DSM Plan period, through the DSM Advisory Group. NS Power remains committed to advancing DR solutions that benefit customers and the overall energy system.
Consumer Advocate (CA)	2024/25 Areas of Focus Work Plan – Accessibility of TVP The Consumer Advocate questions whether renters may face greater barriers to participation in the TVP than homeowners as centers may have less control over their heating sources, appliances, and electricity use. Has NSP considered whether renters face more barriers than homeowners do in accessing TVP? If so, does NSP have a plan to address the barriers renters face in accessing this program?	• The Company recognizes that some renters may encounter unique challenges, in part due to having less control over items such heating sources, or appliance selection, which may cause higher electricity usage then they would have selected themselves. TVP ensures customers, especially renters with the highest energy bills due to energy choices outside of their control, have the flexibility to pursue options to reduce their electricity costs. • NS Power has designed the TVP tariffs to provide customers with choice and flexibility. Importantly, there are no restrictions for renters to join the pilot. Current TVP rates are designed to be technology agnostic and do not require changes to heating sources or appliances to be successful. This can be especially beneficial to renters who do not have these options available to them. This is confirmed by customer survey results[4] that showed the most common changes customers made was behaviour only. The majority of customers on the pilot (68%) have not installed any items since enrolling on the rates. • NS Power welcomes any rate design suggestions stakeholders may have to reduce barriers to energy shifting through rate design for customers, especially those with the highest energy burden. • The Company notes that there were 147 applications from customers identifying as living in an apartment in the Year 3 enrolment cohort (6% of applications). In the most recent Year 4 enrolment cohort that number has increased to 895 customers enrolled identifying as living in an apartment (12% of applications).

[4] M11823 TVP Pilot Program – Year Three Report Appendix B

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NS POWER RESPONSES TO STAKEHOLDER COMMENTS

Stakeholder	Comment	NS Power Response
Consumer Advocate (CA)	<u>2024/25 Areas of Focus Work Plan – Reporting on Small Business Customer Items</u> • Has NS Power looked at the general load characteristics of residential customers that may shift load in response to TVP? Could similar work to that planned for small business customers be undertaken for residential customers? • Has NS Power conducted customer surveys with residential participants and non-participants to help understand why residential customers may be reluctant to participate and what challenges and opportunities there have been?	• Appendix A to the TVP Year Three Report (M11823) highlighted that, for TOU customers, steady electric, and electrified customers were the two residential segments that have demonstrated load shift in response to TVP. CPP customers also demonstrated positive load shift, with evening events yielding statistically significant results for the steady electric segment and morning events yielding statistically significant results for the steady electric, de-electrified, and steady non-electric segments. Currently no small business groups have demonstrated statistically significant positive load shift in response to pricing signals. • NS Power has looked at segmenting customers further with available data to find those customers that correlate most to current winter peaks to determine which customers may have the greatest impact per customer when shifting load. This correlation segmentation on domestic, small general, and general customers will be presented as part of the 2024/25 Work Plan, Technical Session 3. • Customers were surveyed in 2021 as part of pre-onboarding market research; the results were provided as Attachments 1 and 2 to NSPI (SBA) IR-4 in the 2022 Interim Report (M10703). For ease of reference, these attachments have been included as Attachments 1 and 2 to these responses. • As part of the 2024/2025 TVP customer survey, residential participants who left the rate will also be included to help understand challenges they faced with TVP rates leading to them leaving the rate.
Energy Storage Canada (ESC)	<u>Draft 2024/25 Areas of Focus Work Plan (3/5)</u> "Examine customers' correlation with system peaks by rate class." ESC Comment: • In addition to system peaks, would be valuable to understand: ○ how/if the timing of the system peak has been changing, and may change in future.	NS Power agrees that a more detailed discussion around system peak will add value to other discussions completed thought the stakeholder process, including the examination of customers' correlation to those historical peaks. NS Power has revised the 2024/25 Areas of Focus Work Plan to incorporate a discussion around the following topics as part of Technical Session 3 (Review of System Planning Values), which will include:

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NS POWER RESPONSES TO STAKEHOLDER COMMENTS

Stakeholder	Comment	NS Power Response
	○ how the distribution of low- and high-supply cushion hours are expected to evolve. ▪ With an increasing share of wind power, demand-side flexibility in response to supply cushion may gain importance relative to system peaks.	• Why NS Power still views the winter evening peak to be the most likely and impactful time for a system peak moving forward. • How variability in weather systems can affect timing of system peaks, creating the potential for system peak to occur at other times such as the morning or weekend daily peaks. • What role TVP can play in meeting load and reserve requirements. Both though demand side flexibility, as well as by reducing variability in daily load.

NARRATIVE RESEARCH

Nova Scotia Power
Time Variable Pricing Report
Business

July 2021

Prepared for:

Nova Scotia POWER
An Emera Company

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NARRATIVE RESEARCH

Objectives and Methodology

Objectives and Methodology

The following report provides the results of the first phase of research for the ***2021 Time Variable Pricing Study*** conducted on behalf of Nova Scotia Power. Specifically, this version of the report includes only the results of the business customer online survey, and the residential results are provided in a separate document. The purpose of this first phase of research is to better understand customer perceptions regarding the proposed Time Variable Pricing rate plans, namely *Time of Use* and *Critical Peak Pricing*. Results of this survey will be used in subsequent phases of research, as well as assisting Nova Scotia Power in the development of their pilot program.

Specifically, key objectives of this research phase include:

- *Understanding business and residential customers' interest in TOU and CPP structures, including reactions to the concept in general as well as reactions to potential levels of cost savings;*
- *Determining customers' willingness to participate in either TOU or CPP;* and
- *Gauge general customer perceptions of the proposed pricing structures.*

A total of 400 online surveys were collected from business customers, and on average, took participants 23 minutes to complete. In total, 7,643 business customers were invited the survey. Importantly, participants were provided a sharable link if they felt others in their organization were better suited to complete the survey. In all, a response rate of 5% was achieved. Although relatively low compared to the residential survey, this response rate meets expectations when it comes to online business research. Surveys were collected between June 18th and July 4th, 2021.

Throughout this report, firmographic customer analysis is provided. In an effort to identify notable differences between customer subgroups, differences of ten percentage points or more are included in the textual analysis.

NARRATIVE RESEARCH

Summary of Key Findings

Summary of Key Findings

The following highlights are derived from the business customer results from Phase 1 of the 2021 Time Variable Pricing Study:

Of note, a significant minority of customers are unsure how they are currently being billed, while there are also a small proportion of customers that indicated a different rate code than what they are actually on, when asked. Not surprisingly, the majority of customers indicate a moderate to low level of familiarity with their rate plan, while just over one-third express familiarity with the Time of Use concept. When provided a short description, nearly half of business customers express a high level of interest in participating in a Time Variable Pricing program. More specifically, four in ten express likelihood of participating in a Time of Use plan, while just fewer than four in ten are interested in participating in a Critical Peak Pricing Plan. For both plans, business customers most like the fact that these plans could save them money, while disliking the fact that electricity will cost them more during times when the business needs it.

MyAccount

The majority of customers that participated in this online survey were e-billing customers. It is positive to note that e-bill customers express a high degree of satisfaction with the MyAccount experience, and almost all use it at least a few times a year. Most commonly, customers will log in when they get their bill, and few log in more often than once a month. In general, customers are more likely to indicate they review their entire bill thoroughly as opposed to just looking at the amount due.

Usage

Among participants who completed the online survey, ***electricity*** is the most common energy source used for their business' heat, as used by three-quarters, while ***oil*** is used by three in ten and other sources by approximately one in ten each. Just under half of customers have some form of automated or scheduled electronic devices in their business. Automated heating is most common, followed by cooling, while fewer have lighting and other equipment automated. Most commonly, these automated or scheduling devices are installed to save on ***electricity*** and ***heating costs***. Among customers without automated or scheduling devices, interest in installing some in the future is very low. Additionally, among those without automated heating, approximately one-third are interested in installing a smart thermostat in their business in the next three years. The majority of businesses have an ***electric water heater,*** while very few have a heat pump. Meanwhile, just over one in ten report not having a water heater in their business.

Among businesses surveyed, more than half have ***computer servers*** on site that they use and pay electricity for, while a significant minority report paying electricity for ***ventilation, coolers or freezers***, and ***parking garage and/or exterior lighting.***

Summary of Key Findings (continued)

Rate Information and Time Variable Pricing

As noted, four in ten customers express being unsure what rate they are currently on, and overall, customers express a low level of familiarity with their current rate structure. Moreover, two in ten customers mistakenly reported being on Rate 11 (when they are actually Rate 10 customers) and one in ten mistakenly reported being on Rate 10 (when actually on Rate 11). Just over one-third of business customers express familiarity with the Time of Use Rate Plan concept. Further, when provided a short description of Time Variable Pricing, nearly one-half (47%) of business customers expressed a high level of interest in participating should a program like it become available.

Time of Use

Looking at the Time of Use plan specifically, four in ten business customers express a high likelihood of participating in such a plan if it became available. On average, customers would be looking to save 24% of their annual power bill on the program to make it worthwhile, though one-third would be satisfied with 0-15% savings. Most commonly, customers like that the concept offers them ***cheaper rates and a chance to save money***, that ***using power during off peak hours will be better for the environment***, and ***they will have more control over their electricity bill.*** Meanwhile, the greatest dislike or concern about the plan is that ***electricity will cost more during times when they need more power for their business, not being able to adjust their power usage for their business***, and ***in order to save money they would need to change their company practices or behaviours.***

Critical Peak Pricing

Looking at the Critical Peak Pricing plan specifically, just fewer that four in ten business customers express a high likelihood of participating in such a plan if it became available. Once again, customers would be looking to save 25% of their annual power bill on average, though one-third would be satisfied with 0-15% savings. Most commonly, customers like that the concept offers them ***a chance to save money, that using power during off peak hours is better for the environment,*** and ***they will have more control over their bill.*** That said, one-quarter of business customers indicate, unaided, there is ***nothing*** that they like about the plan. Conversely, the greatest dislikes with this plan include ***electricity costing more when their business needs more power***, ***not being able to adjust their business' power usage***, and ***in order to save money they would have to change their company practices or behaviours***.

Preferred Rate Plan

Of the two concepts evaluated, ***Time of Use*** garners greater preference among customers. Overall, one-quarter indicate a preference for ***Time of Use*** when asked to choose, while one in ten prefer the ***Critical Peak Pricing*** option. Two in ten customers indicate they are ***both of equal interest***, while the same proportion are ***not interested in either*** plan. Lastly, just fewer than two in ten are looking to ***learn more*** about the plans before making a decision, and one in ten are ***unsure***.

Summary of Key Findings (continued)

Preferred Rate Plan (Continued)

Among those who prefer the Time of Use plan, the predominant reason is because it ***will provide more benefits and savings***. Meanwhile, those who prefer the Critical Peak Pricing concept most commonly mention it is because of the ***potential cost savings and lower rates throughout the year,*** and it will ***provide control over usage as they can avoid peak times***. Among those who are not interested in either plan, a variety of reasons are mentioned as to why, with the most common being that the ***plans do not allow flexibility and/or they are not able to adjust their usage***. Of those who are looking to learn more before making a decision, they most commonly would like to know a ***cost breakdown of each option to understand how each could save them money.***

When receiving updates and information regarding the program, ***email*** is the preferred method of communication for the majority of customers. Given the large proportion of customers who participated in the survey that are on e-billing, however, it is important to note that a notable minority are also interested in learning more through ***the NSP website,*** by ***having an NSP representative contact them***, ***attached to their bill***, and ***by mail***.

NARRATIVE
RESEARCH

Detailed Analysis

Billing Experience

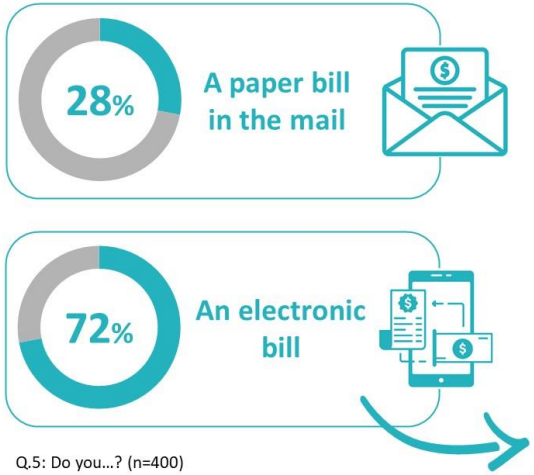
The majority of business customers surveyed are on e-billing and express a high level of satisfaction with the MyAccount experience.

Like residential customers, it is not surprising that a majority of those surveyed are on e-billing as the survey was administered online and could only be delivered to customers with an email address on file.

E-billing is more common among customers on electric heat versus oil, service businesses compared with B2B and Retail, businesses with less than 40 employees, and businesses in buildings less than 10,000 sqft. (Table 5)

Top two box satisfaction (scores of 9 and 10) with the current MyAccount experience is highest among customers in Cape Breton, business types other than B2B, and businesses in buildings less than 5 years old. (Table 6)

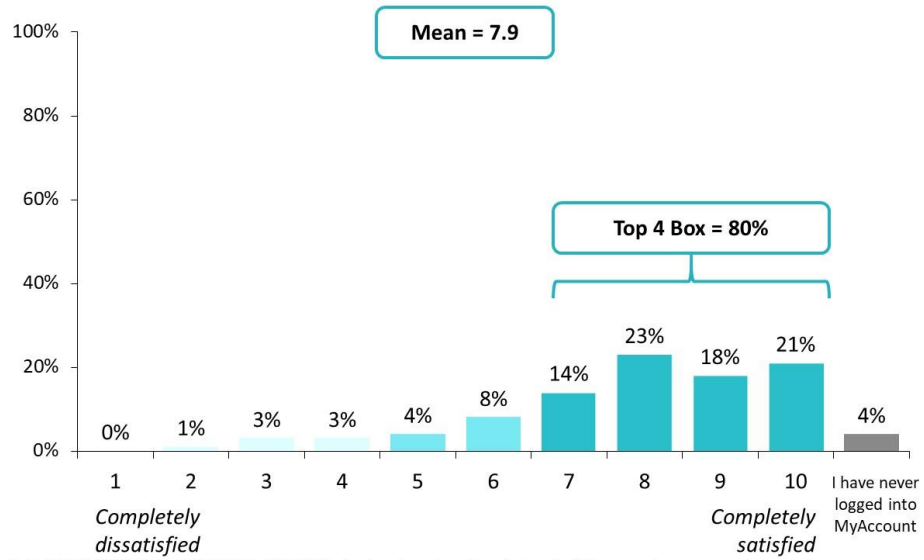
Receive…



Q.5: Do you…? (n=400)

Satisfaction with Current MyAccount Experience

Among Those Who Receive an Electronic Bill



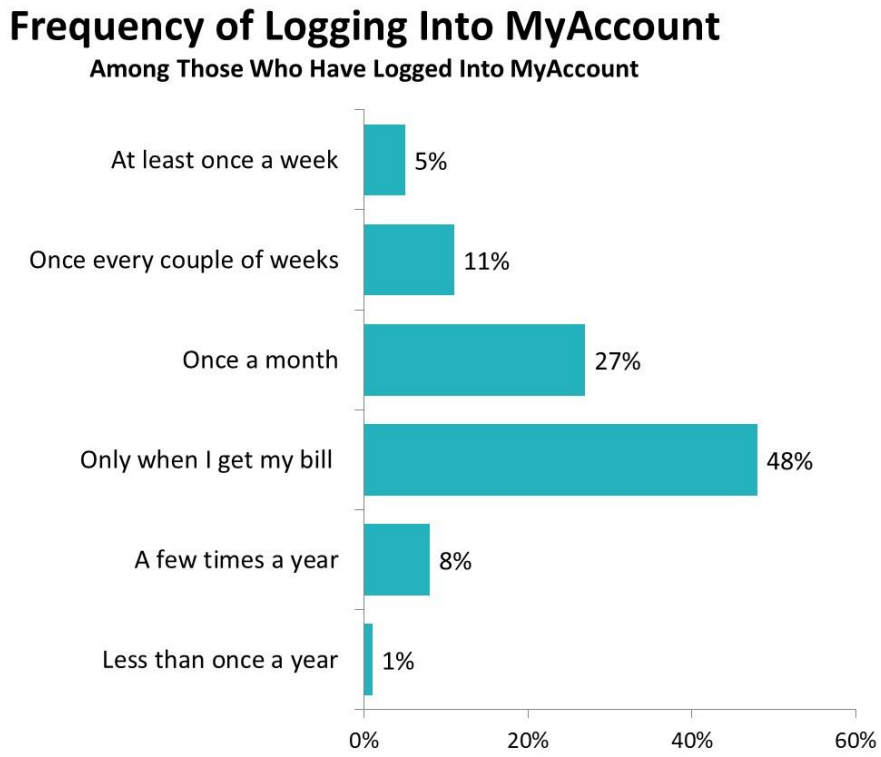
Q.6: **[IF RECEIVE ELECTRONIC BILL IN Q.5]** By having signed up for electronic billing, you have access to an online MyAccount profile. How satisfied are you with the current MyAccount experience? (n=285) *Note: 'I have never logged into MyAccount' is excluded from the box score and mean.*

MyAccount

Most commonly, one-half of customers only log into their MyAccount when they get their bill, while one-quarter log in monthly.

It is comparatively much less common for customers to log in more than once a month.

Results overall are similar across customer subgroups. That said, customers in the wester region are most likely to log in only when they get their bill, while MURB and retail businesses are most likely to log in once a month. (Table 7)



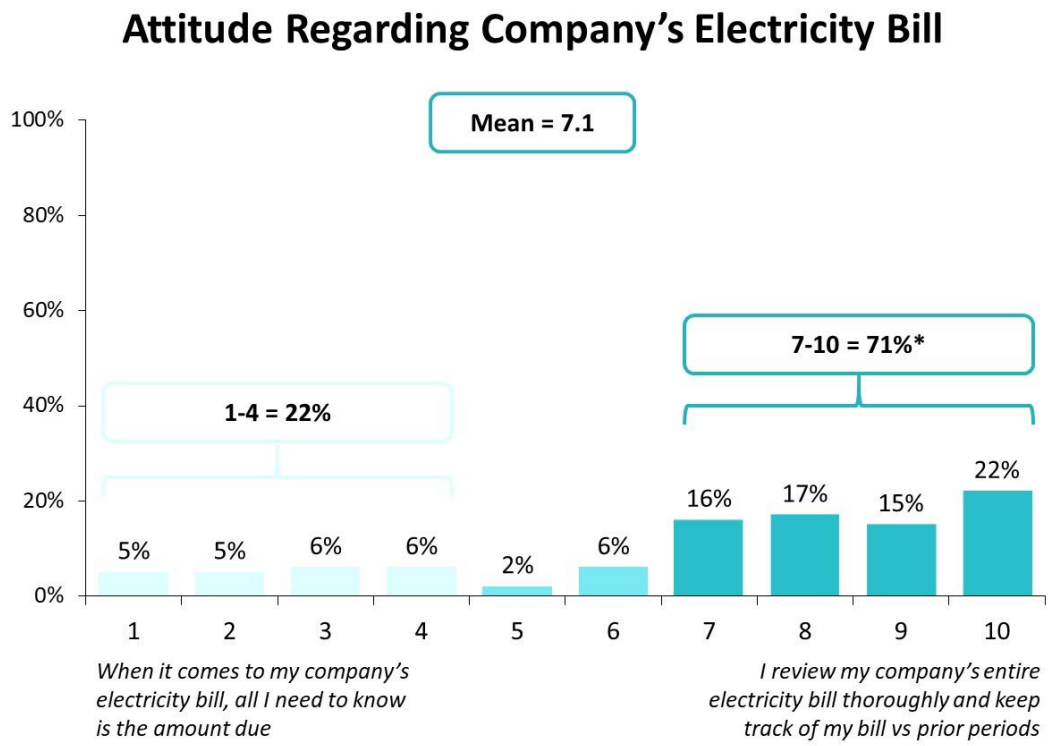
Q.7: **[IF RATED 1-10 IN Q.6]** How often do you log into MyAccount. (n=273)

Electricity Bill

The majority of customers are more likely to review their bill thoroughly and keep track of trends, as opposed to simply paying the amount owed.

Customers were presented a sliding scale and asked where their opinion lies between two statements. The majority of customers (71%) more closely align with the statement ***I review my entire electricity bill thoroughly and keep track of my bill or usage trends***, while two in ten (22%) more closely align with the statement ***when it comes to my electricity bill, all I need to know is the amount due.*** The question was similarly asked on the residential survey and results are nearly identical (71% and 20% respectively).

Across firmographics, businesses outside of Cape Breton, businesses in building of at least 2,500 sqft., and customers on paper billing, are more likely to review their entire electricity bill thoroughly. (Table 8)



Q.8: For the following statement, please indicate where your opinion lies by moving the slider along the line. (n=400) **Due to rounding.*

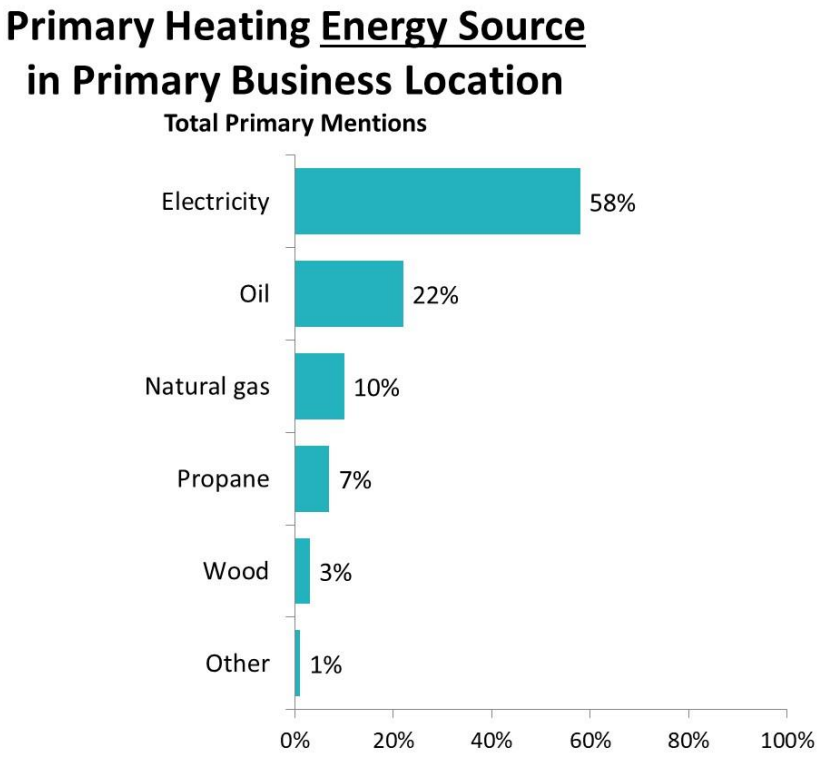
NARRATIVE
RESEARCH

Usage

Primary Heat Source

More than one-half of customers use electric heat as their primary heat source in their business, while two in ten use oil.

Electric heat is greater among customers with fewer employees, and customers in buildings under 2,500 square feet. Electric heat is also more common among e-billing customers, buildings under 10 years old, businesses in the Western region, business types other than MURB, and rate 10 customers. (Table 10)



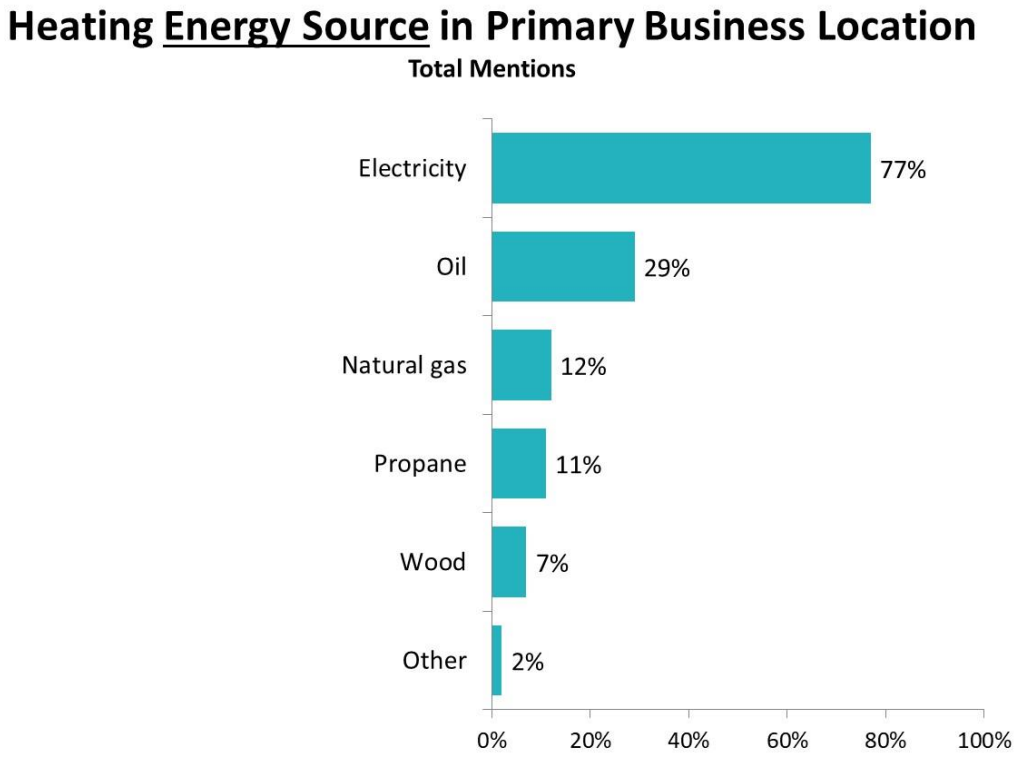
Q.10: What are the sources of heat for your business at your primary business location? (n=400)

Home Heating Energy Sources

In terms of total heat sources customers have in their business, electricity is used by three-quarters, while oil is used by three in ten.

Other sources of heat are much less common among business customers.

Oil heat is more common among customers outside of Metro, while Metro customers are more likely than customers in other regions to have natural gas. Customers in the Western region are most likely to have electric heat. Oil heat is also more common among businesses in older buildings, and buildings of at least 2,500 square feet. (Table 10)

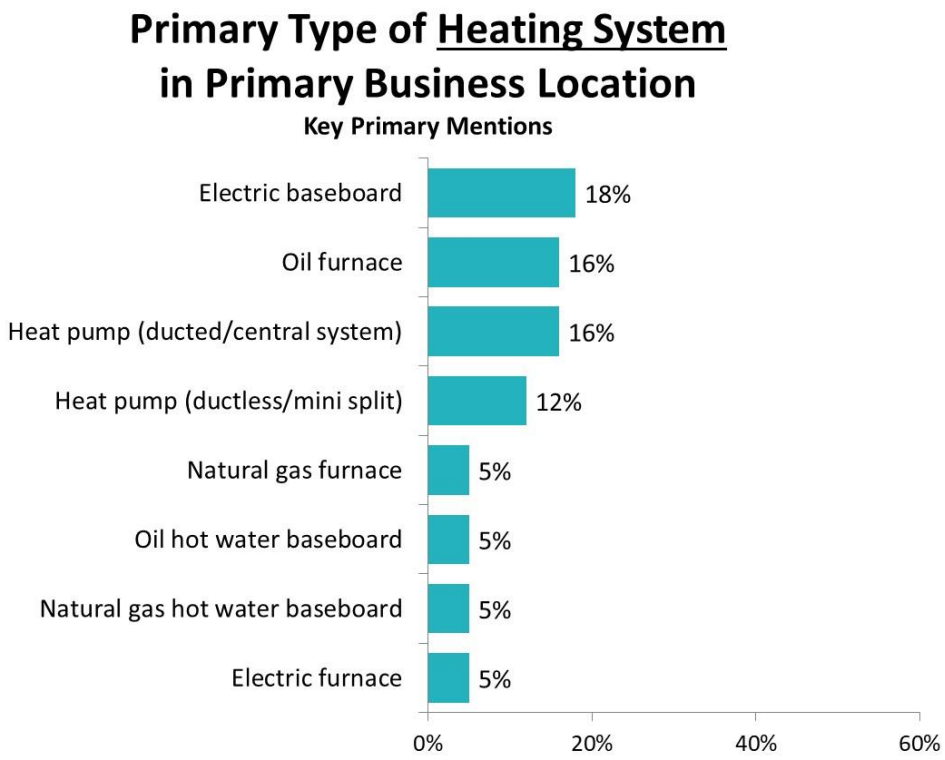


Q.10: What are the sources of heat for your business at your primary business location? (n=400)

Primary Heating System

In terms of heating systems, electric baseboard, oil furnace, and heat pumps (ducted and ductless) are most common.

More specifically, two in ten each use ***electric baseboards***, while just fewer use an ***oil furnace*** or ***ducted heat pump*** as their primary heating system, while approximately one in in ten use a ***ductless heat pump***. Other heating systems are comparatively less common. (Table 10)

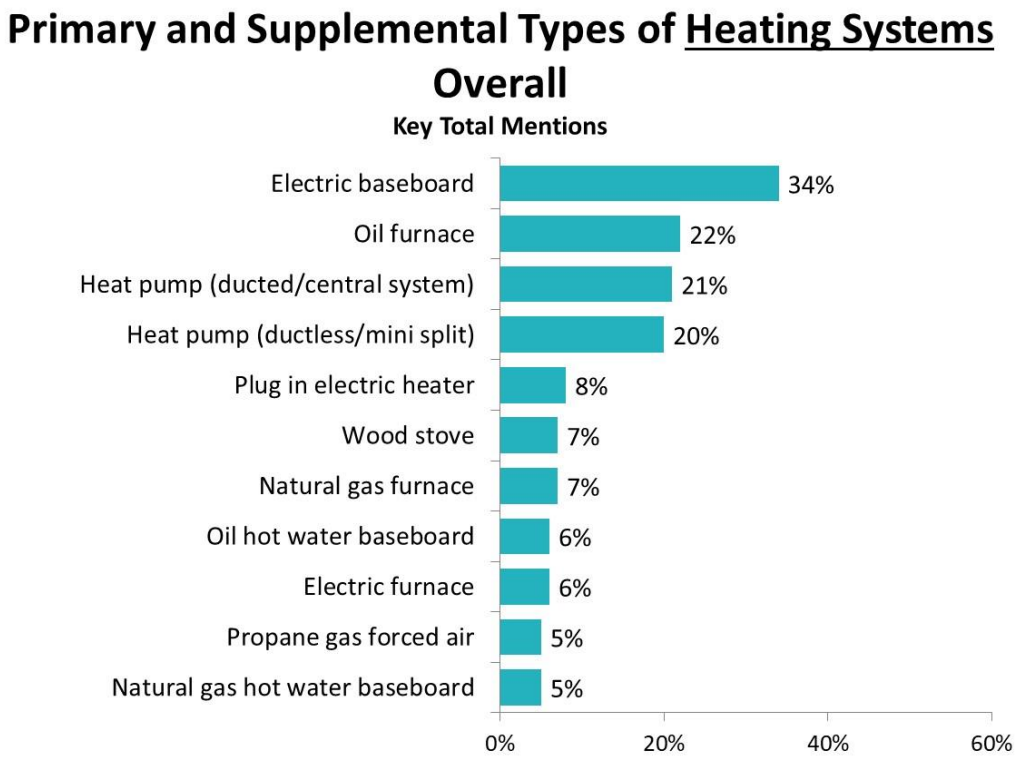


Q.10: What are the sources of heat for your business at your primary business location? (n=400)

Home Heating Systems (Overall)

Across all heating systems that customers have in their business, electric baseboards are most common, with oil furnaces and heat pumps (ducted and ductless) closely trailing.

As many customers have multiple heating systems within their business (e.g., a primary system and a supplementary back-up system), the graph to the right displays the key total incidence of heating systems customers have. (Table 10)



Q.10: What are the sources of heat for your business at your primary business location? (n=400)

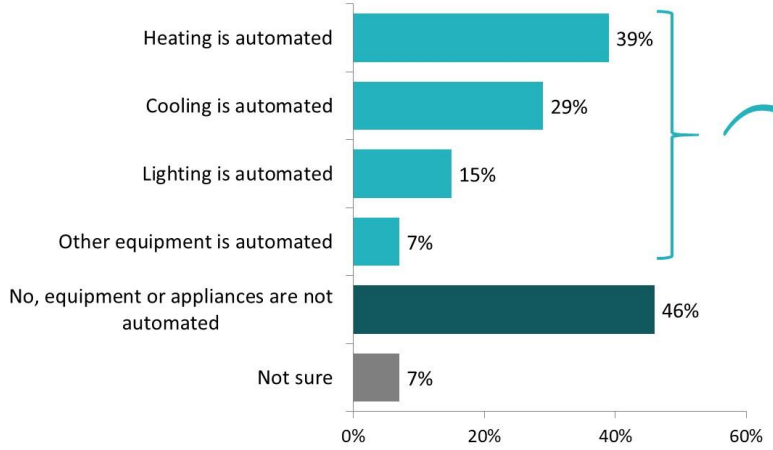
Automation

Four in ten customers have automated heating in their business, while a third have automated cooling and just over one in ten have automated lighting.

Businesses were asked whether they had various forms of automated or scheduled electronic devices. Of note, just under one-half of customers do not have any form of automation for their equipment or appliances. Among those who do, (n=189) the most common reasons for installing these devices was to ***save on electricity*** (60%) and to ***save on heating costs*** (57%). Of note, one-third also mentioned it was ***to set schedules*** (32%), while the same proportion also mentioned it was ***to be more environmentally friendly*** (32%). (Table 11 and 12)

Types of Automated or Scheduled Electronic Devices/Equipment in Business

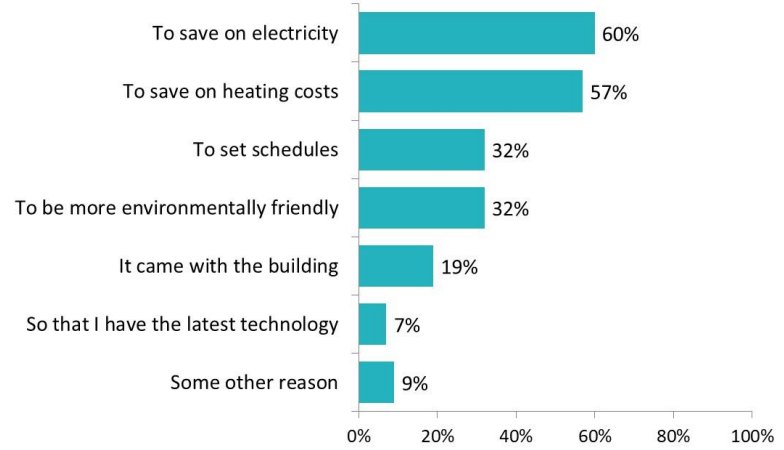
Total Aided Mentions



Q.11: Do you have any automated or scheduled electronic devices/equipment in your business? For example, heating, cooling, lighting or equipment that turns on and off on a schedule. Please select all that apply. (n=400)

Reasons for Installing Automated/Scheduled Devices or Equipment in Business

Total Aided Mentions Among Those Who Automated Equipment



Q.12: **[IF AUTOMATED EQUIPMENT (CODES 1-4) IN Q.11]** Thinking about the automated/scheduled devices or equipment that you have installed in your business, what are the most important reasons as to why you installed them? Please select all. (n=189)

Automation (Continued)

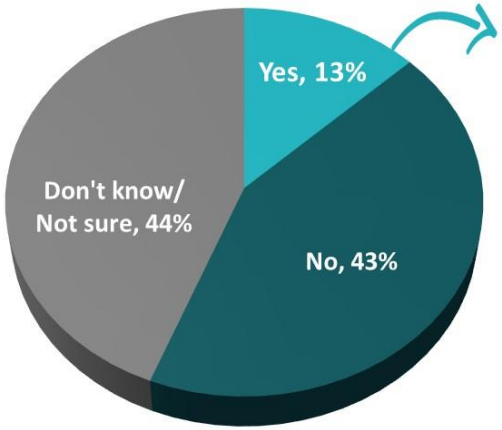
Among customers without automated equipment, interest is low in installing these types of devices in the future.

Of those who have no form of automated equipment or devices (46%; n=185), only 13 percent indicate being interested in installing automated equipment in the past.

That said, among businesses that are interested (13%; n=23) the key reasons for their interest are to ***schedule their heating based on use***, and to ***save on electricity/heating costs***. Of note, caution should be taken when interpreting firmographic differences given small sample sizes. (Tables 13 and 14)

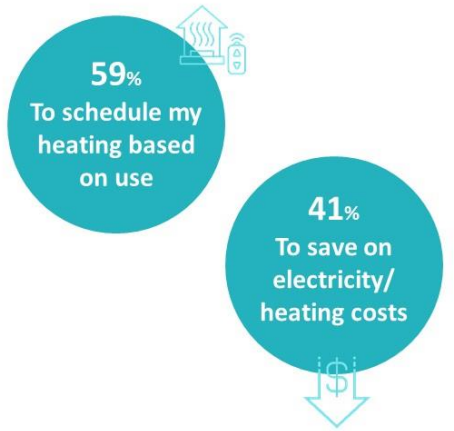
Interested in Installing Automated Equipment

Among Those Who Do Not Currently Have Automated Equipment in Business



Reasons Interested Installing Automated Equipment in Business

Total Aided Mentions Among Those Who Would Be Interested In Automated Equipment



Q.13: **[IF 'NO, EQUIPMENT OR APPLIANCES ARE NOT AUTOMATED' IN Q.11]** Would you be interested in installing automated/ scheduling devices or equipment in your business? (n=185)
Q.14: **[IF YES IN Q.13]** What is the single most important reason why you might be interested in installing automated/scheduling devices or equipment? (n=23)* **Caution: Small sample size*

Likelihood of Installing Smart Thermostat

Among customers without automated heating, one-third express a high likelihood of installing a smart thermostat in the next three years.

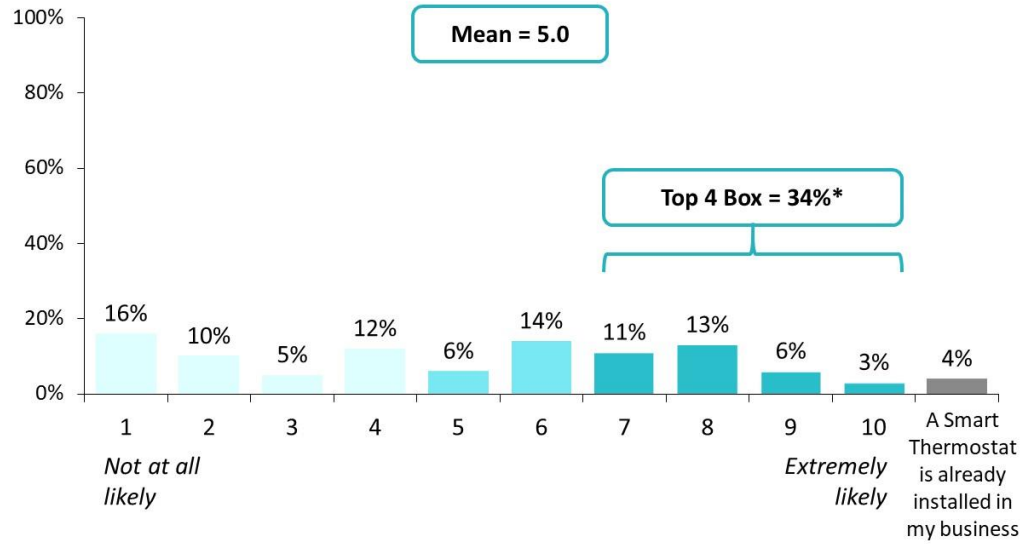
Although a minority, this result suggests that smart thermostats could see greater adoption among businesses in the near future.

Likelihood of installing a smart thermostat is greater among business types that aren't B2B, businesses with less than 40 employees, buildings less than five years old, and customers on rate code 11. Once again, small sample sizes among some firmographic subgroups warrant caution when interpreting differences. (Table 15)

Smart thermostats work by helping to set heating schedules (e.g., raise temperature during business hours and lower temperature outside business hours), allow you to control the thermostat while away from your workplace on your smart phone, among other features.

Likelihood of Installing a Smart Thermostat in Business in the Next Three Years

Among Electric Heat Customers (Primary/Secondary) Who Do Not Have Automated Heating



Q.15: **[IF ELECTRIC HEAT CUSTOMERS (PRIMARY/SECONDARY) AND 'NO, EQUIPMENT OR APPLIANCES ARE NOT AUTOMATED' IN Q.11]** How likely are you to install a smart thermostat in your business in the next three years? (n=179)

*Note: Responses of 'A Smart Thermostat is already installed in my business' are excluded from the calculation of all summary statistics. *Due to rounding.*

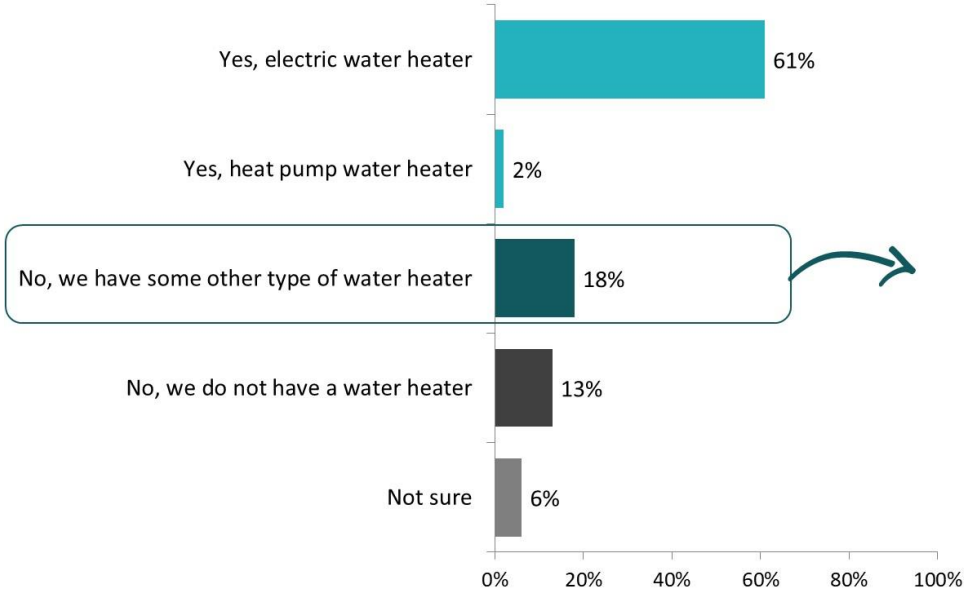
Water Heater

Electric water heaters are most common among business customers.

The majority of business customers have an ***electric water heater***, while very few (2%) have a ***heat pump water heater***. Meanwhile, two in ten have ***some other type of water heater*** (18%), with ***oil, propane,*** *and* ***natural gas*** being most common. Of note, only 13 percent of business customers do not have a water heater in their business.

Non-electric/heat pump water heaters are more common among customers that do not use electricity as their primary heating source, while also more common among customers without a heat pump, those in the Northeast region, multi-unit residential and service businesses, those in larger buildings (2,500sqft+) and rate 11 businesses. (Table 16)

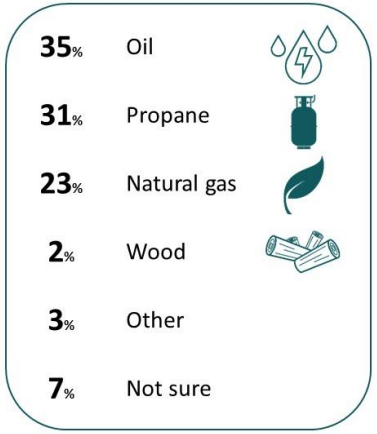
Have an Electric or Heat Pump Water Heater



Q.16: Do you have an electric or heat pump water heater? (n=400)

Heat Source Used By Water Heater

Total Aided Mentions Among Those Who Have Water Heater Other Than Electric or Heat Pump



Q.16a: **[IF 'NO, WE HAVE SOME OTHER TYPE OF WATER HEATER' IN Q.16]** What heat source does your water heater use? (n=69)

Electric Devices

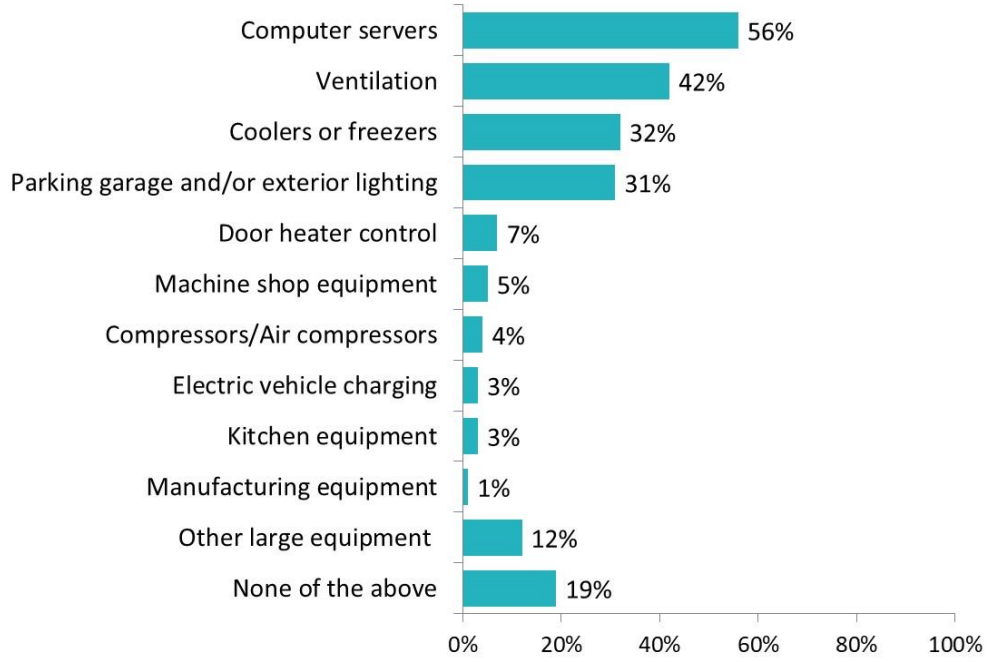
Computer servers, ventilation, coolers/freezers, and exterior lighting are the most common major equipment business customers pay for at their business location.

Business customer were also asked the type of equipment they use and pay electricity for in their primary business location. Most commonly, as mentioned by more than half, ***computer servers*** are located in their primary business location, while four in ten also pay the electricity for ***ventilation.*** One-third each also pay for ***coolers or freezers***, and ***parking garage and/or exterior lighting.*** Comparatively, other types of equipment are much less common.

Businesses with heat pumps are more likely to pay the electricity for computer servers and ventilation. Meanwhile, businesses with more employees, greater square footage, and on rate 11 are more likely to pay the electricity for computer servers, ventilation, coolers and freezers, exterior lighting, or other large equipment. (Table 17)

Use and Pay Electricity for in Primary Business Location

Total Aided Mentions



Q.17: Which of the following do you use and pay the electricity for **in your primary business location**? Select all that apply. (n=400)

NARRATIVE RESEARCH

Rate Information - General

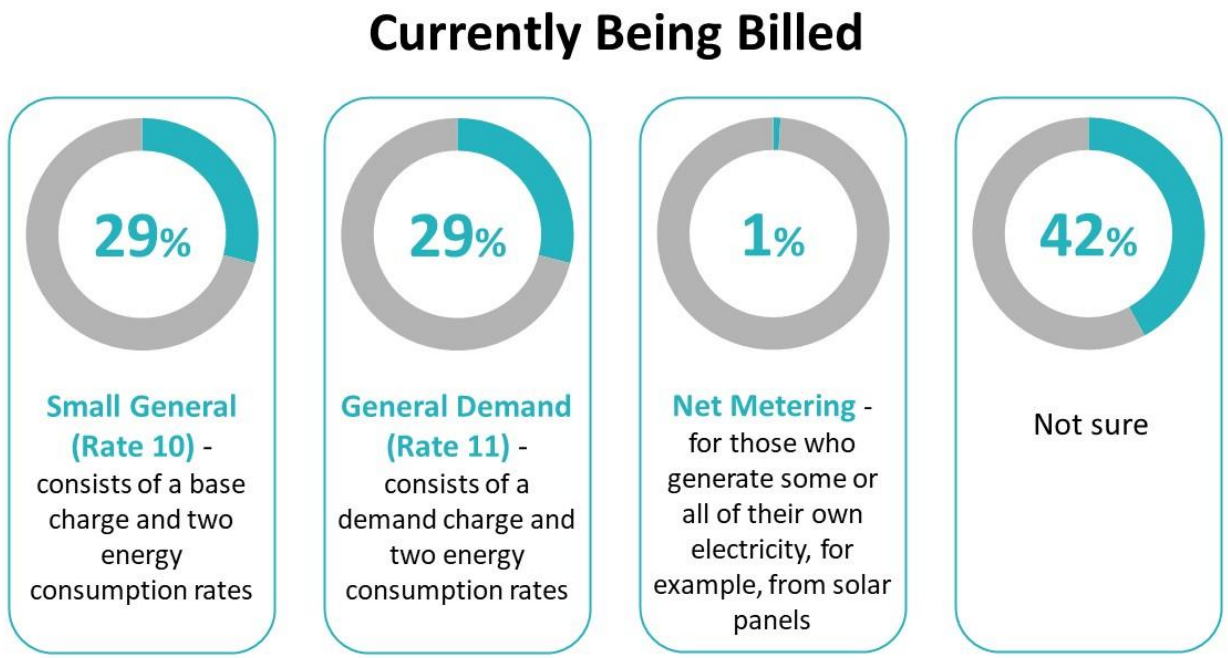
Rate Type

Confirming assumptions, many customers are unsure what rate plan they are on.

Approximately three in ten each report being on ***Small General billing (Rate 10)***, and ***General Demand billing (Rate 11)***. Comparatively, only one percent report being on ***Net Metering***.

Of note, four in ten business customers indicate that they are ***unsure*** what type of rate code they are on (43% of rate 10 businesses and 38% of rate 11). In addition, it was identified that 19% of rate 10 customers incorrectly indicated being on rate 11, while 11% of rate 11 customers incorrectly reported being on rate 10.

Uncertainty is greater among those on electric heat versus oil, service type businesses, those with fewer employees, those with less than 10,000 sqft., e-bill customers, and those in newer buildings. Uncertainty, however, is similar between rate 10 and 11 customers. (Table 18)



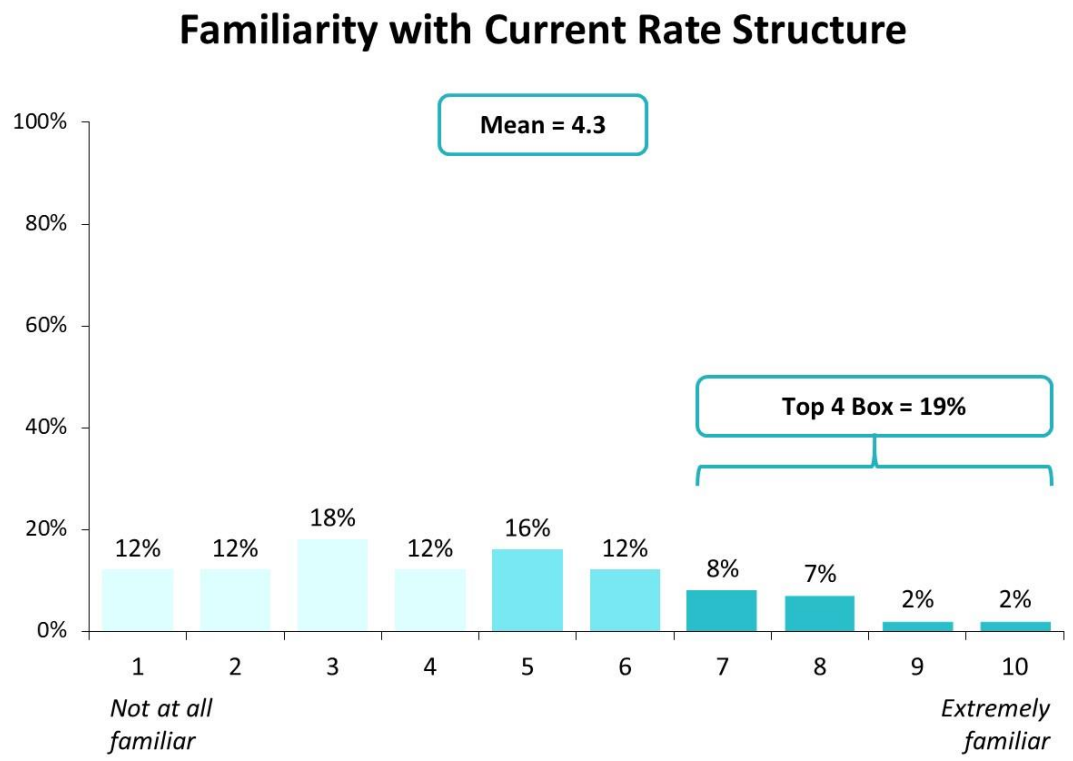
Q.18: How are you currently being billed? (n=400)

Familiarity with Current Rate

Overall, business customers express limited familiarity with their current rate.

Notably, only two in ten indicate that they are highly familiar with their current standard rate, while customers overall provide a mean score of four on a ten point scale. Further, more than half (54%) express ***unfamiliarity***, scores of 1 to 4.

Familiarity levels are similar between rate 10 and rate 11 customers, though other firmographic differences are observed. Notably, higher familiarity is reported by paper billing customers, businesses with 10,000 or more sqft., 40 or more employees, other than service and B2B businesses, and Cape Breton based businesses versus those in Northeast and West. (Table 19)



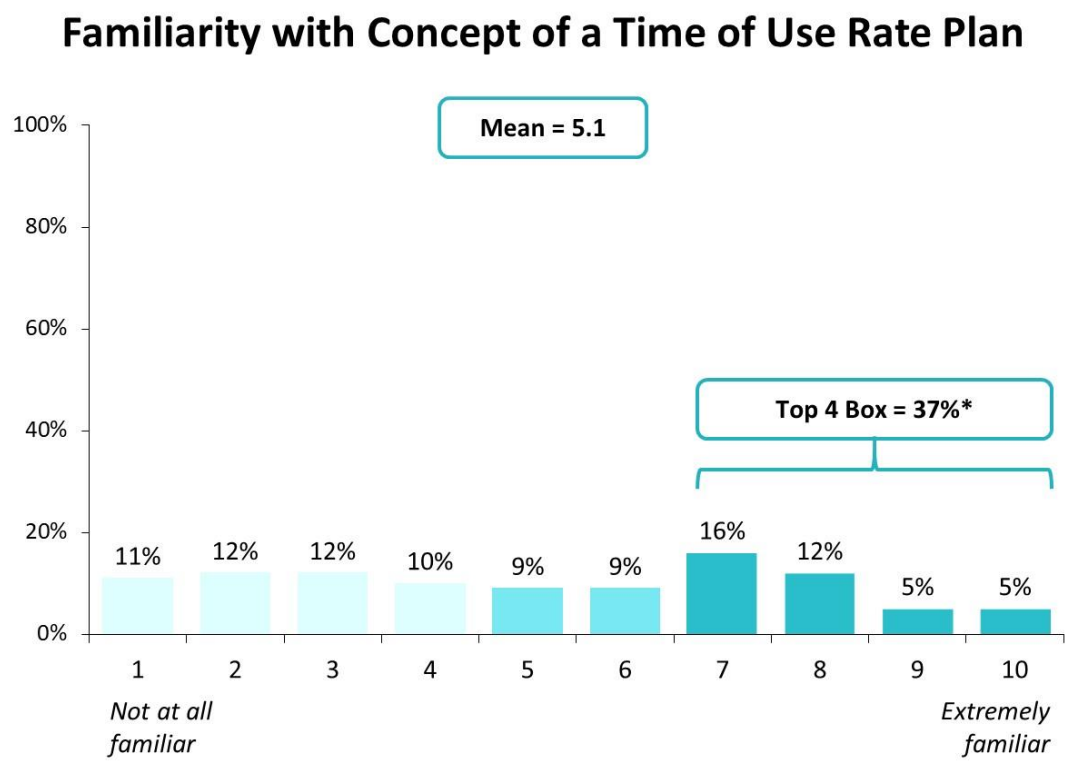
Q.19: How familiar are you with your current rate structure? (n=400)

Familiarity with Time of Use

Overall, more than one-third of customers express a high level of familiarity with the Time of Use rate plan concept.

Customers express a varying degree of familiarity with the Time of Use plan with more than one-third of customers indicating a high level of familiarity while more than four in ten (45%), express a low level of familiarity (scores of 1-4).

Familiarity is lowest among B2B customers, while highest among those with 10,000 or more sqft., versus those with less than 2,500, those in buildings less than five years old, and rate 11 customers. (Table 20)



Q.20: How familiar are you with the concept of a ***Time of Use Rate Plan***? (n=400) **Due to rounding.*

NARRATIVE RESEARCH

Rate Information

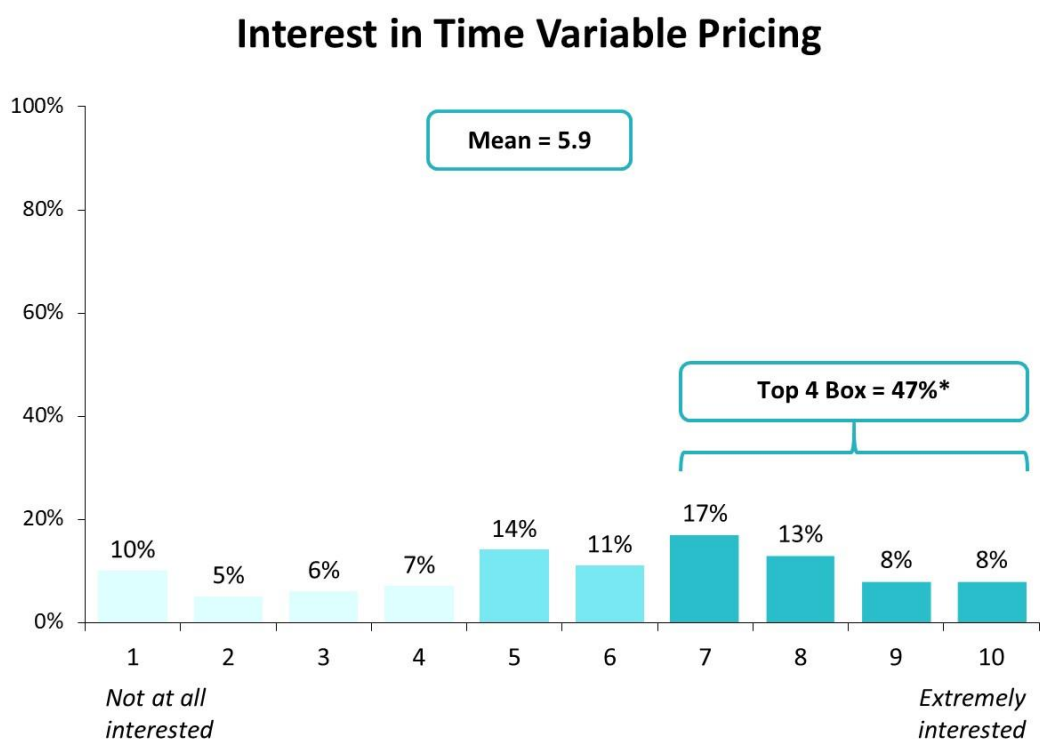
Interest in Time Variable Pricing

Following a brief description, there is a relatively high level of interest in the general concept of Time Variable Pricing, with just under one-half expressing interest.

Customers were provided with a brief description of the TVP concept and asked for their level of interest in participating in such a program. It is positive to note that just under one-half (47%) express a high level of interest, while only three in ten provide a low level of interest (28%; scores of 1-4).

Across customer firmographics, interest is greatest among customers in Cape Breton, service based businesses compared to retail and B2B, those with 10,000 or more sqft., and those in buildings less than 5 years of age. (Table 21)

Nova Scotia Power is considering offering two new rate pricing offers. For customers who choose to sign up, the price of electricity would vary between summer (April to October) and winter months (November to March). In the winter, the price would fluctuate throughout the day. For example, the rates for electricity would be higher when demand is higher (i.e., early morning and early evening hours). To offset the higher winter rate, lower rates are applied during summer months.



Q.21: Overall, how interested would you be in participating in a program like this if it became available? (n=400) *Due to rounding.*

NARRATIVE RESEARCH

Time of Use

Likelihood of Participating in Time of Use Plan

Customers were then provided a description of the proposed Time of Use Plan, overall four in ten express likelihood of participating in the new plan.

Overall, there is a relatively high level of interest in participating in the proposed Time of Use plan, with four in ten customers expressing a high likelihood of participating if it became available.

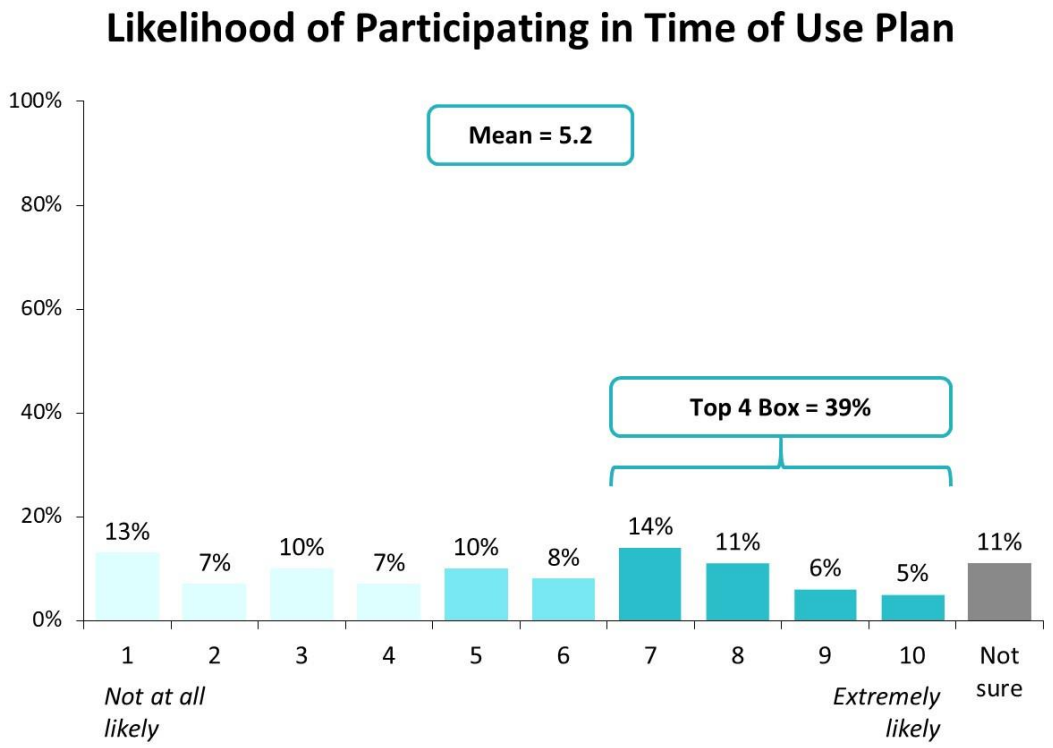
Of note, while presented as Option A and B in this report, customers were presented the Time of Use and Critical Peak Pricing in random order to prevent order bias in the results.

Those who express a high level of likelihood of participating in Time of Use are less likely to express a high likelihood of participating in Critical Peak Pricing.

Overall, across customer firmographics, likelihood of participating is greatest among businesses other than multi-unit residential buildings (MURB), and those in buildings less than five years old, similar. (Table 22)

Option A: *Time of Use*

With the Time of Use Plan, winter weekdays (November to March) will be divided into peak and off-peak hours. Rates will be higher during peak hours to reflect the higher cost of providing energy during that period. The Time of Use Plan will allow customers to choose how they use their electricity to take advantage of lower rates during off-peak hours (which includes weekends and holidays). For business customers this could mean shifting the use of high energy consuming equipment, building energy management systems or leveraging technology like electric thermal storage. For the rest of the year (April to October), the price for energy would be less than the current standard rate.



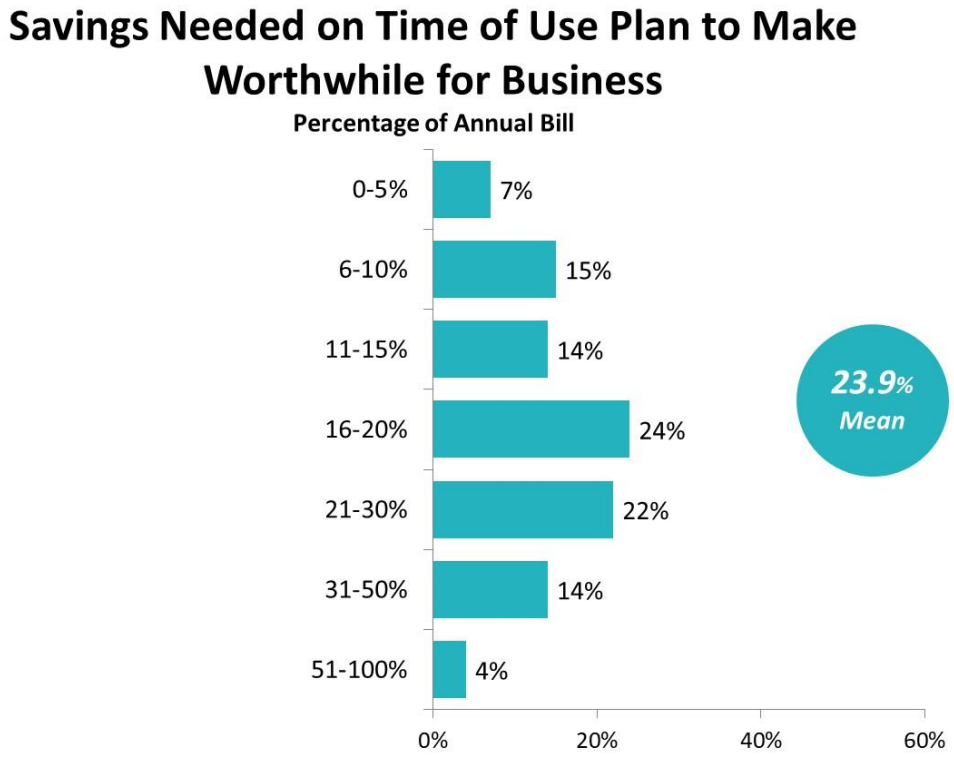
Q.22: Based on this description, how likely would you be to participate in this type of plan? (n=400) *Note: Responses of 'Not sure' are excluded from all summary statistics.*

Savings Required (Time of Use)

Customers would need to save 24%, on average, on their bill each year to make the Time of Use plan worthwhile to them.

Business customers were next asked the proportion of their electrical bill they would need to save in order to make the plan worthwhile for them. On average, customers would be looking to save 24 percent of their annual bill, though one-third of customers would only need to save 0 to 15 percent. Meanwhile, nearly half (46%) would be looking to save 16 to 30 percent, and two in ten (18%) would be looking to save 31 percent or more.

Overall, savings required to make the program worthwhile are similar across customer firmographics. (Table 22a)

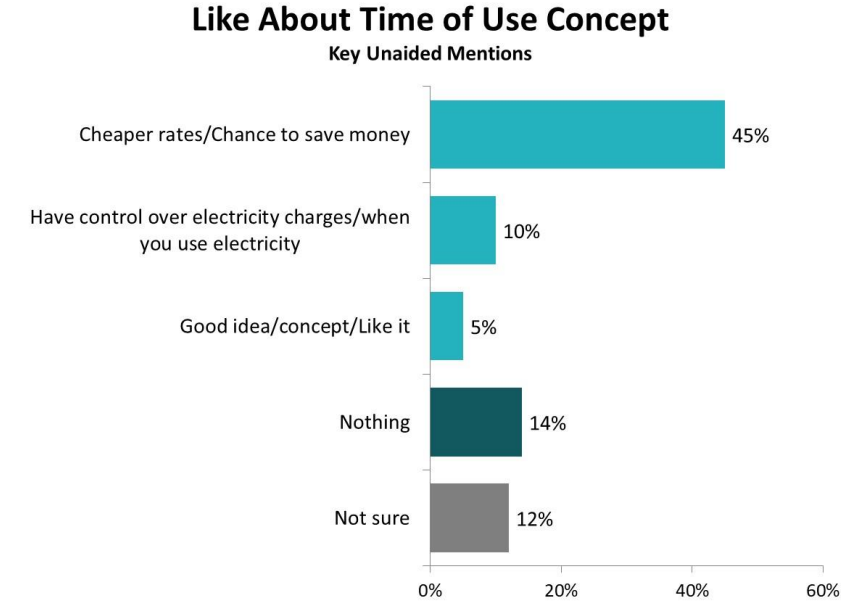


Q.22a: How much would you need to save on your bill each year to make this plan worthwhile for your business? (n=400)

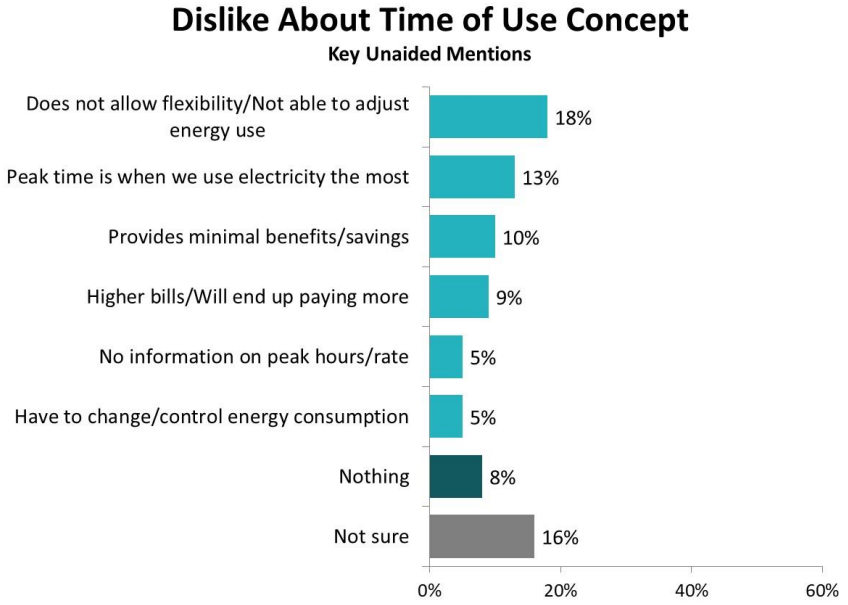
Likes and Dislikes of Time of Use

Customers most like the chance to save money on the Time of Use rate plan, while a variety of dislikes are mentioned by a small proportion each.

Unaided, customers most frequently mention liking the ***chance to save money*** on the Time of Use plan, while one in ten also mention liking the ability to ***have control over electricity charges***. In terms of dislikes, two in ten mention that ***the plan does not allow flexibility and that they are unable to adjust their energy use***, while approximately one in ten or fewer each mention disliking that ***peak times are when they use the most electricity***, perceptions that it ***provides minimal savings, leads to higher bills***, ***not having enough information on peak hours***, and ***having to change their consumption***. Of note, results displayed on this page reflect verbatim comments of customers shared in an open-ended question that were then coded into categories. (Table 24a and b)



Q.24a: What do you **like** about this concept? (n=400)

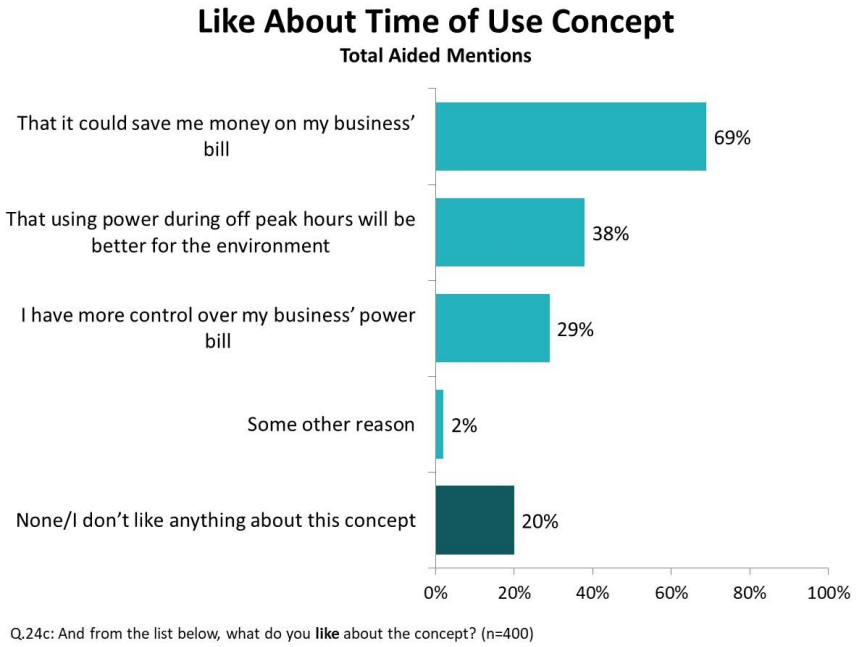


Q.24b: What do you **dislike** about this concept? (n=400)

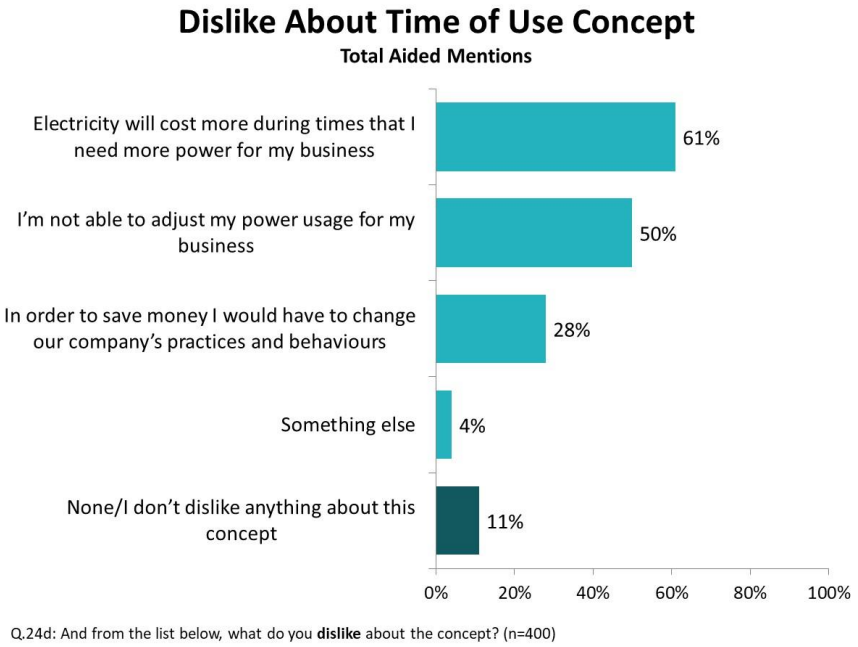
Likes and Dislikes of Time of Use (Continued)

Customers were once again asked what they liked and disliked about the Time of Use concept, this time prompted with options to choose from.

Most commonly, customers like ***that they could save money on their bill***, as selected by seven in ten, while just over a third also like ***that using power during off peak hours will be better for the environment***, while three in ten like that ***they will have more control over their electricity bill.*** Meanwhile, more than one-half of customers dislike that ***electricity will cost more during times when they need it most,*** and half dislike the concept because ***they are unable to adjust their power usage***. Additionally, three in ten dislike that ***in order to save money, they would have to change their company practices/behaviours.*** (Tables 24c and d)



Q.24c: And from the list below, what do you **like** about the concept? (n=400)



Q.24d: And from the list below, what do you **dislike** about the concept? (n=400)

NARRATIVE RESEARCH

Critical Peak Pricing

Likelihood of Participating in Critical Peak Pricing

Customers were provided a description of the proposed Critical Peak Pricing rate plan. Overall, more than one-third express a high likelihood of participating.

There is near identical likelihood that business customers would participate in the proposed Critical Peak Pricing plan as compared to the Time of Use plan. Of note, just under four in ten customers express being highly likely to participate, while just over four in ten (44%) express a low likelihood (scores of 1-4).

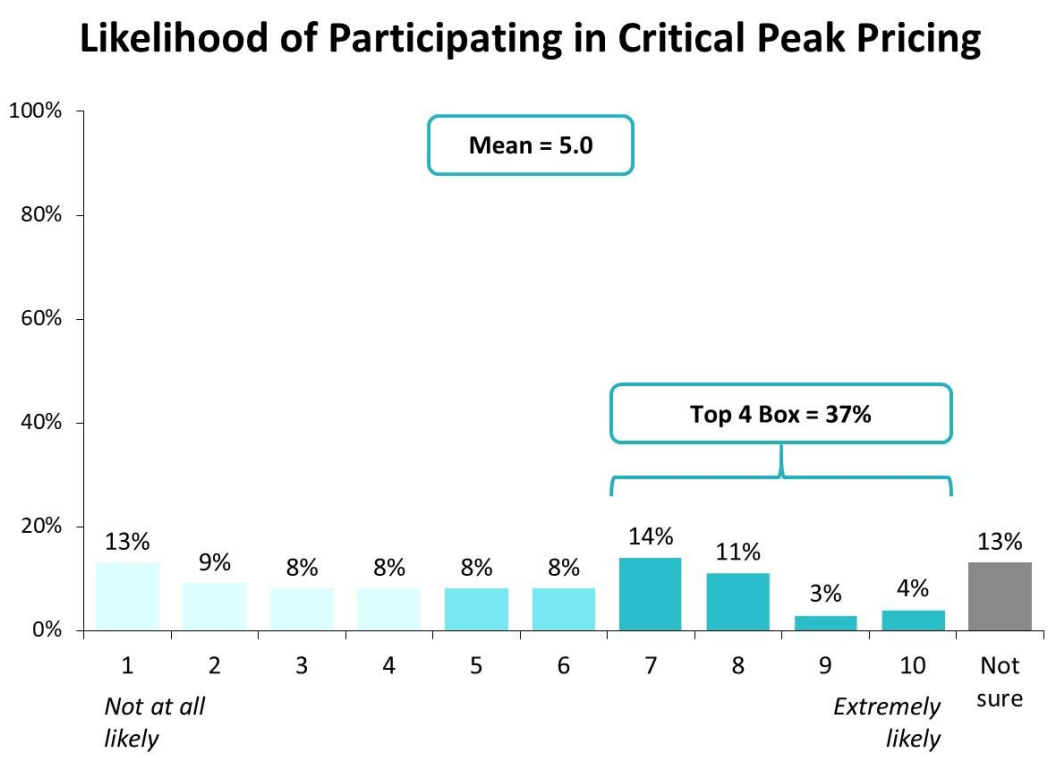
As noted, while presented as Option A and B in this report, customers were presented the Time of Use and Critical Peak Pricing in random order to prevent order bias in the results.

Those who express a high level of likelihood of participating in Critical Peak Pricing, are less likely to express a high likelihood of participating in Time of Use. This is similarly observed among Time of Use results suggesting that some customers express a clear preference for one plan over the other.

Across firmographics, interest in this plan is greater among non-MURB businesses, and businesses in newer buildings. (Table 23)

Option B: *Critical Peak Pricing*

The Critical Peak Pricing Plan will provide customers with a rate that is lower than the current standard rate. On winter weekdays from November to March, when the electrical grid is at peak capacity, Nova Scotia Power may announce a "Critical Peak Event". There would be up to a maximum of 22, four-hour events, being 1% or less of the hours in a year. These peak events reflect the higher cost of providing energy during that period. Customers on this plan would be notified by text message and/or email the day prior and directly before the critical peak event occurs, providing them the ability to adjust their electricity use to manage costs. Outside of critical peak events, the price for energy would be less than the current standard rate.



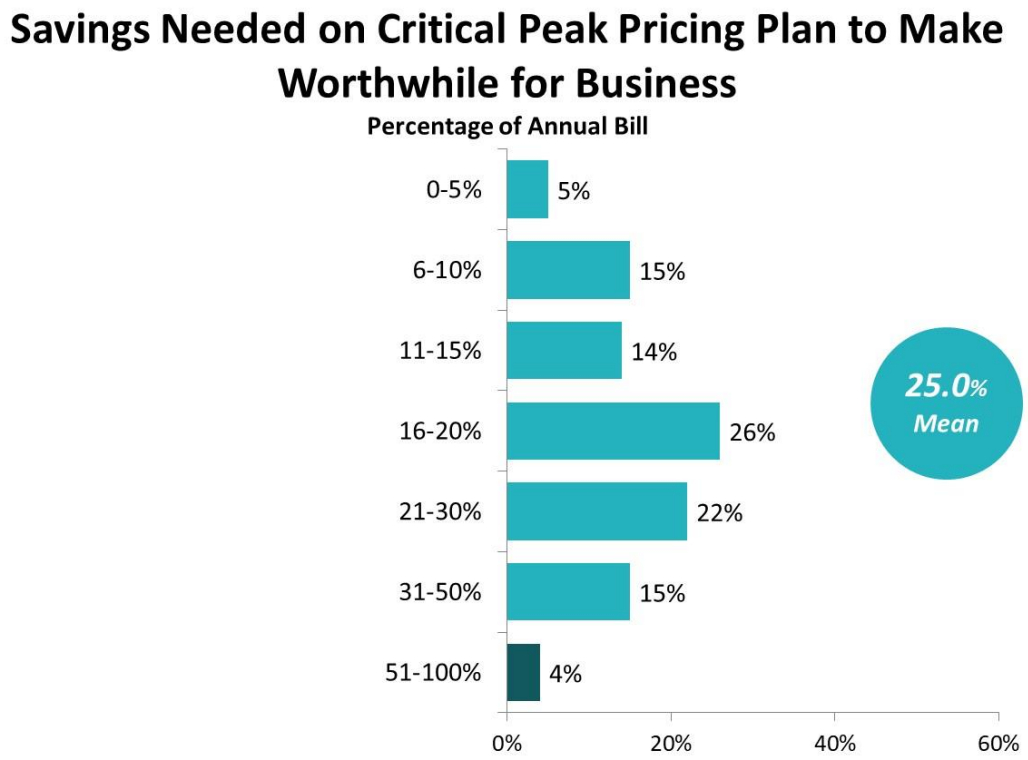
Q.23: Based on this description, how likely would you be to participate in this type of plan? (n=400) *Note: Responses of 'Not sure' are excluded from all summary statistics.*

Savings Required (Critical Peak Pricing)

Customers would need to save 25%, on average, on their bill each year to make the Critical Peak Pricing plan worthwhile.

Business customers were next asked the proportion of their electrical bill they would need to save in order to make the plan worthwhile for them. On average, customers would be looking to save 25 percent of their annual bill, a result that is highly similar to Time of Use (24%). One-third of customers indicate they would need to save 0 to 15 percent, while a quarter (26%) would be looking to save 16 to 20 percent, and an additional nearly quarter (22% would be looking to save 21 – 30%, two in ten (19%) would be looking to save 31 percent or more.

Overall, savings required to make the program worthwhile are similar across customer firmographics. That said, businesses with fewer than 40 employees indicate requiring a greater proportion of savings. (Table 23a)

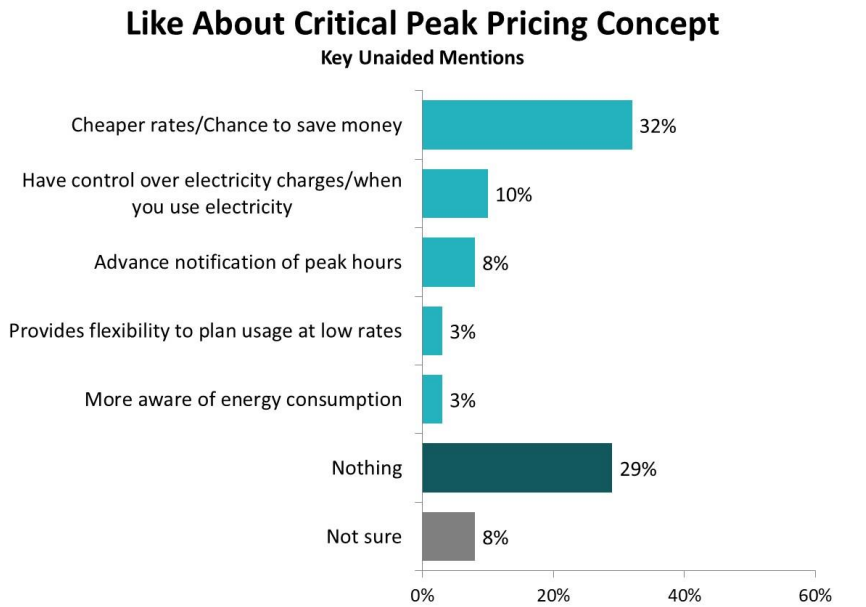


Q.23a: How much would you need to save on your bill each year to make this plan worthwhile for your business? (n=400)

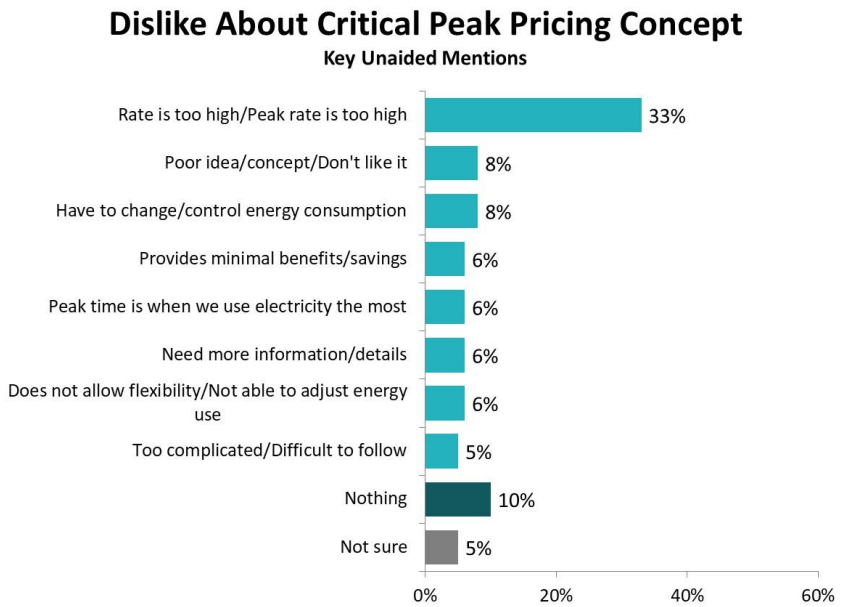
Likes and Dislikes of Critical Peak Pricing

Unaided, customers most like the chance to save money on their electricity bill, while most dislike the perception that peak rates are too high.

Most commonly, one-third of customers note liking the ***cheaper rates and chance to save money***. That said, three in ten indicate they ***do not like anything about the concept***. This is compared to 14 percent who said the same about the Time of Use concept. When asked what customers dislike about the concept, ***rates being too high*** are most commonly mentioned by one-third. Results are also consistent with the residential findings. Of note, results displayed on this page reflect verbatim comments of customers shared in an open-ended question that were then coded into categories. (Tables 25a and b)



Q.25a: What do you **like** about this concept? (n=500) *Note: 500 responses were chosen at random for coding for this question.*

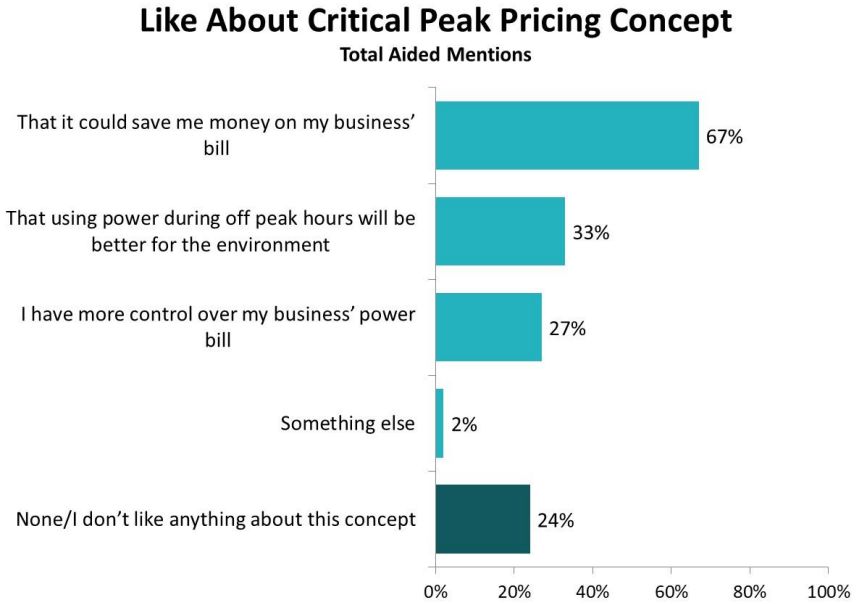


Q.25b: What do you **dislike** about this concept? (n=500) *Note: 500 responses were chosen at random for coding for this question.*

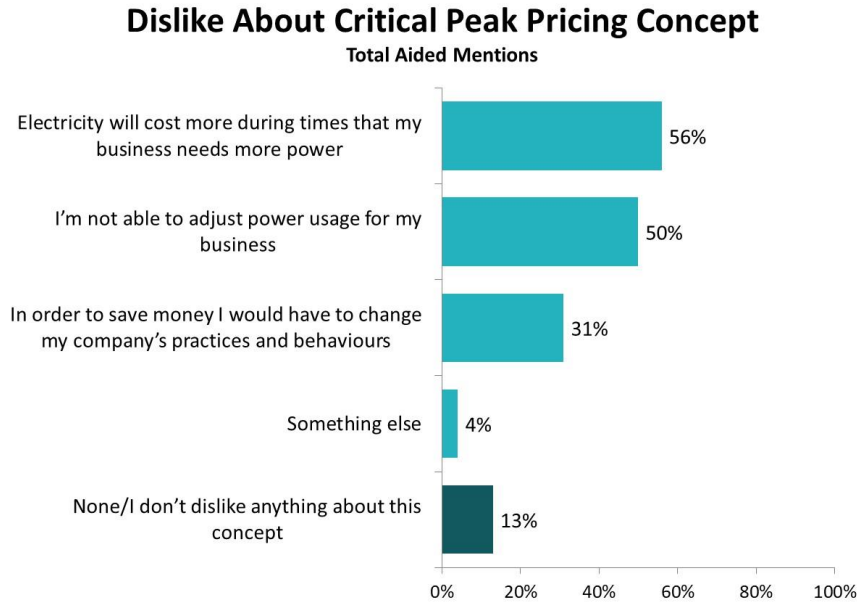
Likes and Dislikes of Critical Peak Pricing (Continued)

Customers were once again asked what they liked and disliked about the Critical Peak Pricing concept, this time prompted with options to choose from.

Most commonly, customers like ***that they could save money on their bill***, as selected by two-thirds, while one-third like that ***using power during off peak hours will be better for the environment*** and one-quarter like that ***they will have more control over their electricity bill.*** Meanwhile, more than one-half of customers dislike that ***electricity will cost more during times when they need it most,*** and a similar one-half indicate ***not being able to adjust their power usage,*** while three in ten dislike that ***in order to save money they would need to change their behaviour.*** (Tables 25c and d)



Q.25c: And from the list below, what do you **like** about the concept? (n=400)



Q.25d: And from the list below, what do you **dislike** about the concept? (n=400)

NARRATIVE
RESEARCH

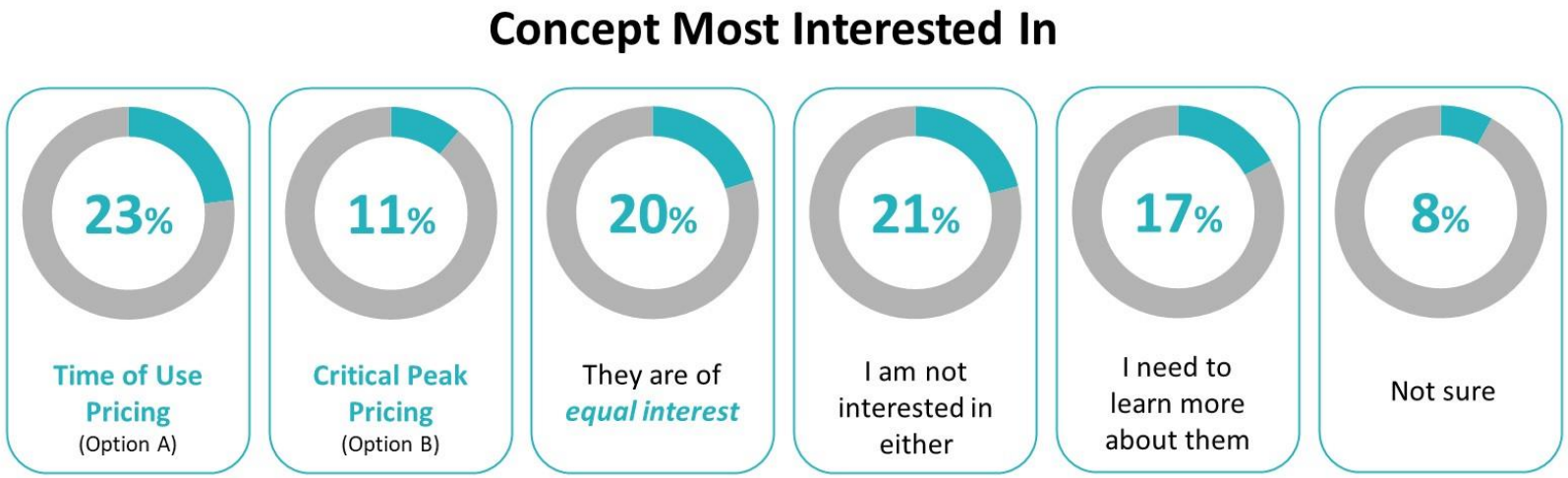
Preferred Rate Plan

Preferred Rate Plan

Between the two rate plans proposed, customers express greater interest in the Time of Use plan overall, though two in ten are equally interested in both.

More specifically, one-quarter of customers select the ***Time of Use plan*** as being most of interest to them, while only one in ten select the ***Critical Peak Pricing plan***. Meanwhile, two in ten indicate ***they are of equal interest***, while two in ten ***are not interested in either plan***. Additionally, just fewer than two in ten would ***need to learn more about the plans***, and one in ten are ***unsure***.

Preferences for Time of Use and Critical Peak Pricing are similar across customer firmographics. Meanwhile, electrically heated customers, those with heat pumps and those in a building less than five years old, are more likely to ***need to learn more***. (Table 24)



Q.24: Of the two concepts being considered, which is of greater interest to you? (n=400)

Reasons for Greater Interest in Time of Use

Of those most interested in Time of Use, the main reason is because the plan will provide more benefits and savings, followed by mentions that it would be easier to implement and fit their schedule.

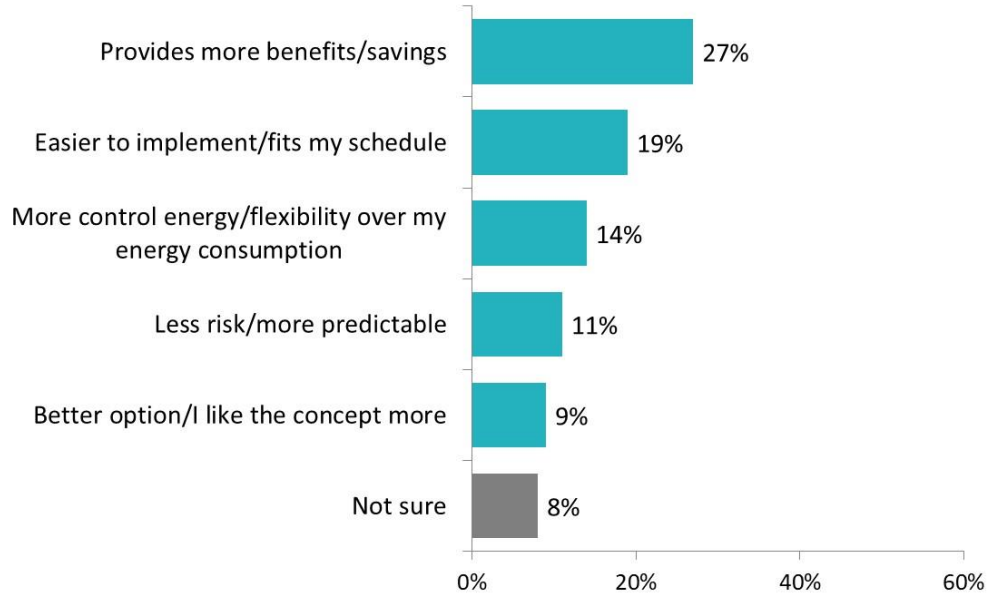
Most commonly, one-quarter indicate their preference for the Time of Use plan because it ***will provide more benefits and savings,*** while two in ten note that it ***is easier to implement into their schedule***. A smaller proportion each also mention that it ***offers more control over their energy consumption, less risky/more predictable than Critical Peak Pricing,*** and because they perceive it to be a ***better option***.

Caution should be taken when interpreting some customer demographic subgroups given small sample sizes. (Table 26a – Time of Use)

23% ***Are more interested in Time of Use Pricing***

Reasons for Greater Interest in Time of Use Pricing

Key Unaided Mentions
Among Those Who Are More Interested in Option A – Time of Use Pricing



Q.26a: **[IF INTERESTED IN OPTION A – TIME OF USE PRICING IN Q.24]** Why are you more interested in Option A – Time of Use Pricing? Please be as specific as possible. (n=93)

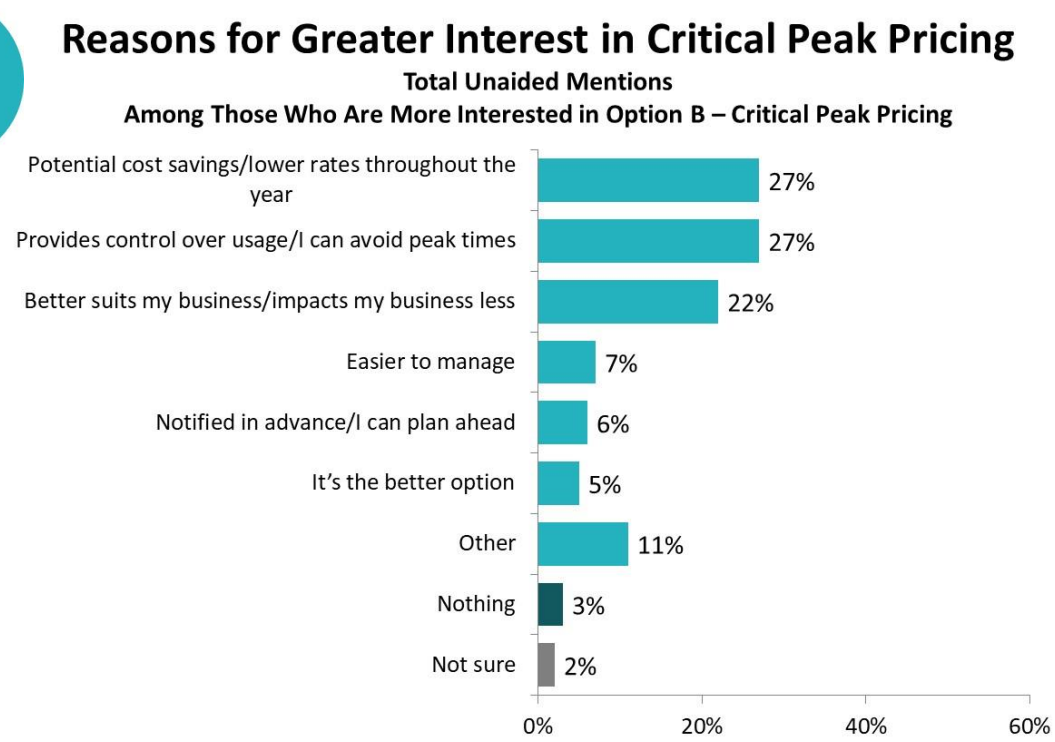
Reasons for Greater Interest in Critical Peak Pricing

Of those most interested in Critical Peak Pricing, the main reasons are because of potential cost savings and providing more control over their usage.

Most commonly, one-quarter indicate their preference for the Critical Peak Pricing plan because of its ***potential cost savings and lower rates throughout the year*** and because it ***provides more control over their usage/they can avoid peak times.*** A slightly smaller proportion also indicate that this option ***better suits their business/impacts their business to a lesser extent.***

Caution should be taken when interpreting some customer demographic subgroups given small sample sizes. (Table 26a – Critical Peak Pricing)

11% ***Are more interested in Critical Peak Pricing***



Q.26a: **[IF INTERESTED IN OPTION B – CRITICAL PEAK PRICING IN Q.24]** Why are you more interested in Option B – Critical Peak Pricing? Please be as specific as possible. (n=45)* **Caution: Small sample size.*

Reasons for Disinterest in Either Plan

Customers not interested in either program provide a variety of reasons as to why, with a perceived lack of flexibility most commonly mentioned.

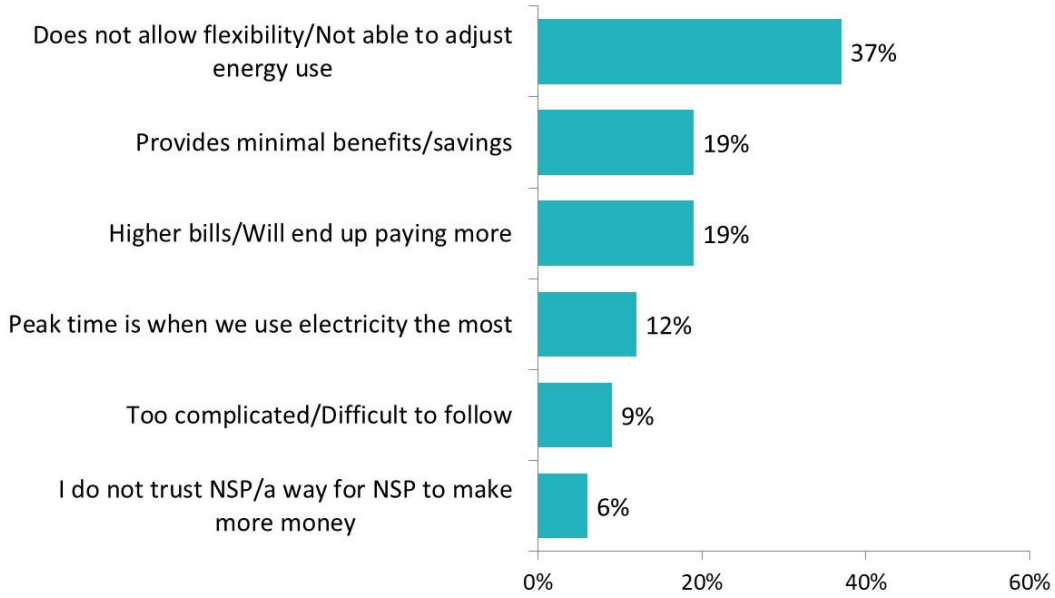
Most commonly, customers express being not interested in either pricing plan because they perceive it to ***not allow flexibility*** (37%), that ***it provides minimal benefits*** (19%), ***bills will be higher*** (19%), ***peak times are when they use the most electricity*** (12%), ***it is too complicated*** (9%), and ***they do not trust NSP*** (6%), among other reasons.

Caution should be taken when interpreting some customer demographic subgroups given small sample sizes. (Table 26b)

21% ***Are not interested in either pricing plan***

Reasons for Not Being Interested in Either Pricing Plan

Key Unaided Mentions
Among Those Who Are Not Interested in Either Pricing Plan



Q.26b: **[IF NOT INTERESTED IN EITHER OPTION IN Q.24]** Why are you not interested in either pricing plan? Please be as specific as possible. (n=83)

Interest in Learning More

Customers who express being interested in learning more before choosing between the two plans would most commonly like to see a cost breakdown of each option and better understand how each could save them money.

One-third of customers interested in learning more about the pricing programs indicate that ***seeing a cost breakdown of each option*** would help them make a decision.

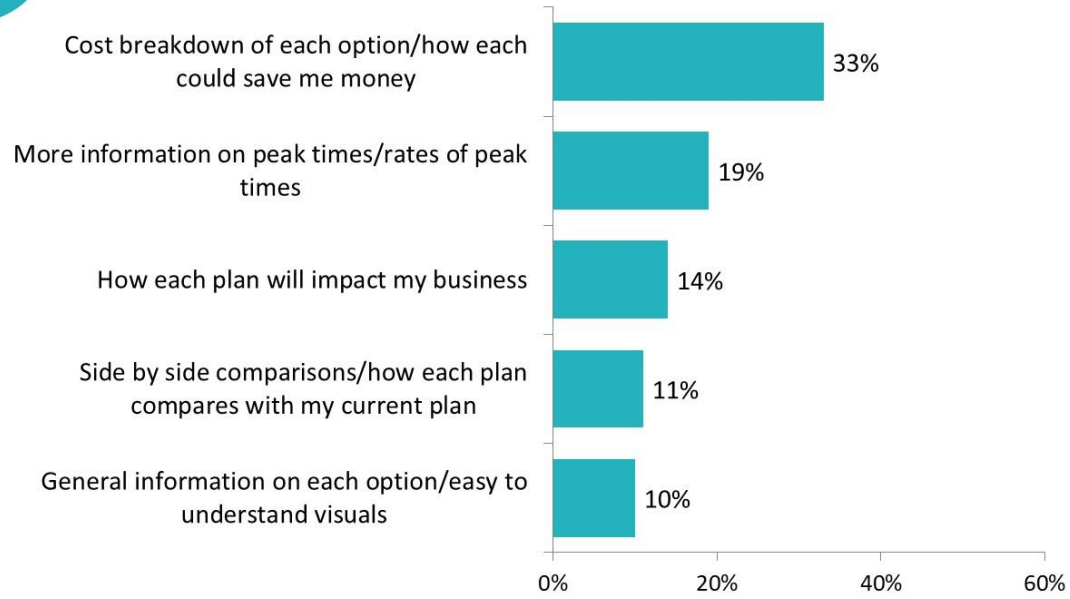
Meanwhile, customers also mention wanting to learn more ***information on peak times and rates, how each plan will impact their business, a side by side comparison of plans,*** and ***general information on each option including some easy to understand visuals***.

Once again, caution should be taken when interpreting some customer demographic subgroups given small sample sizes. (Table 26c)

17% ***Would like to learn more about the pricing plans***

Interested in Learning More About

Key Unaided Mentions
Among Those Who Would Need to Learn More About the Pricing Plans



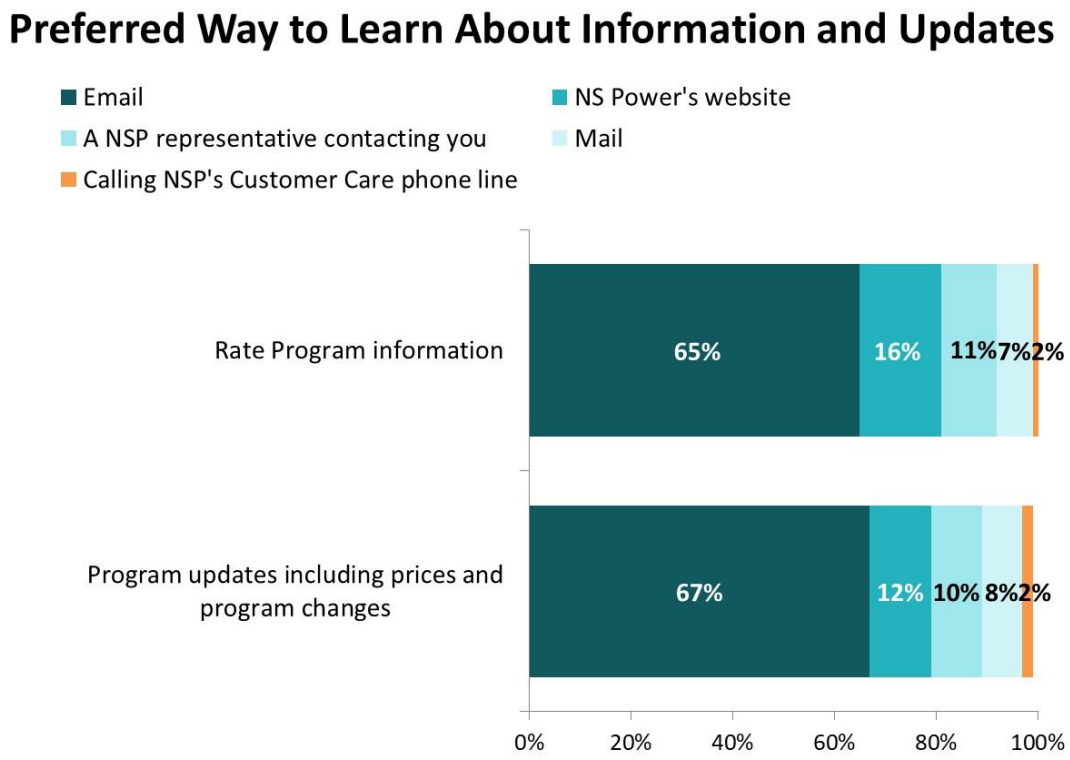
Q.26c: **[IF WOULD NEED TO LEARN MORE ABOUT THEM IN Q.26]** What specifically are you interested in learning more about? Please be as specific as possible. (n=68)

Preferred Means of Learning More

When learning about rate program information and program updates, email is by far the most preferred method of communication.

For both ***rate program information*** and ***program updates including prices and program changes***, the majority of customers would prefer to receive these updates through ***email***. Meanwhile, fewer than two in ten each would like to receive them through the ***Nova Scotia Power website***, while approximately one in ten each would like to have ***a Nova Scotia Power representative contact them***, or by ***mail.*** Only two percent of customers would like to receive these updates by ***calling NSP's Customer Care phone line***. This finding could perhaps be perceived as customers wanting NSP to be proactive in notifying them of information, rather than needing to contact the utility to find out more by themselves.

Not surprisingly, ***email*** is more likely to be preferred by e-billing customers, and those in buildings less than 10 years old. Otherwise, preferred communication methods are similar across customer demographics. (Tables 25aa and bb)



Q25aa-bb: What would be your preferred way to learn more about each of the following? (n=400)

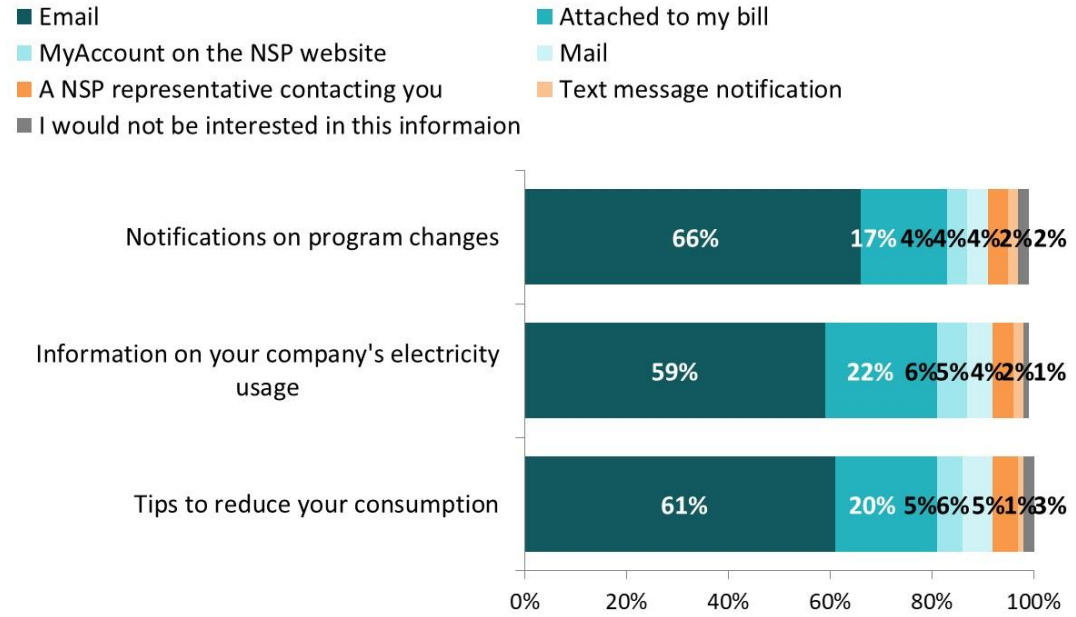
Preferred Means of Receiving Notifications

When participating in a program, program updates would be most preferred by email.

Similar to more general program updates, customers were asked how they would like to receive ***notifications on program changes, information on personal electricity usage***, and ***tips to reduce consumption***, if they were participating in one of these proposed programs. For each type of update, the majority would prefer to receive it by ***email***, while a small proportion would also be interested in receiving a notice ***attached to their bill***. Comparatively few would prefer to receive notifications via other means.

Once again, e-bill customers and those in newer buildings (less than five years old) are much more likely to prefer receiving each of these notifications through ***email***, while paper bill customers are much more likely to prefer updates ***attached to their bill***. Otherwise, preferences are similar across most firmographics. (Table 26aa-cc)

Preferred Way to Receive Notifications and Information



Q26aa-cc: If you were participating in one of these programs, Nova Scotia Power would also have the ability to send notifications and share customized information regarding your business' electricity usage (e.g., to let you know which appliances are using the most electricity and customized tips on how to lower your power bill). For each of the items below, please select your most preferred way to receive it. (n=400)

NARRATIVE RESEARCH

Firmographic Profile

Firmographic Profile

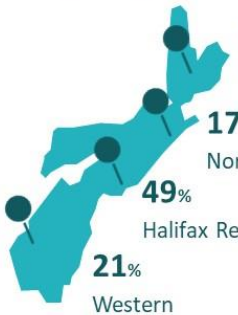
The following provides a brief profile of the business customers that participated in the survey.

Firmographic Profile *(n=400)*

28% *Receive a* **paper bill**

72% *Receive an* **electronic bill**

Primary Business Location

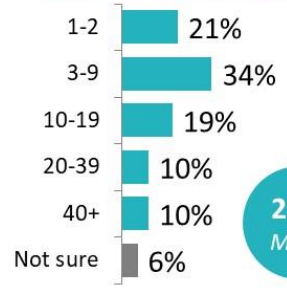


- **13%** Cape Breton
- **17%** Northeastern
- **49%** Halifax Regional Municipality
- **21%** Western

Industry
(Key Mentions)

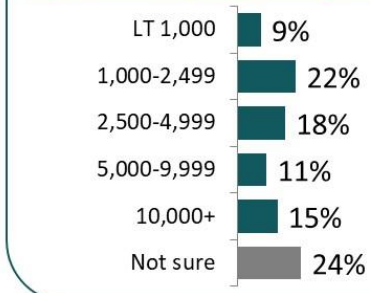
- **17%** Retail stores
- **11%** Restaurants
- **9%** Property Management
- **9%** Manufacturing
- **8%** Multi-residential buildings
- **5%** Agriculture
- **5%** Automotive services

Number of Employees



22.3 *Mean*

Square Footage of Primary Business



Operate...	Mon	Tues	Wed	Thur	Fri
Prior to 7am	20%	20%	20%	20%	20%
7am-9pm	87%	88%	89%	89%	88%
After 9pm	17%	18%	18%	18%	17%
Do not	5%	3%	1%	1%	2%

64% *Operate on* **Saturday**

48% *Operate on* **Sunday**

Seasonal Electricity Changes in Business Operations

- **44%** Use **more** electricity in the **winter**
- **12%** Use **more** electricity in the **summer**
- **3%** Some other seasonal change
- **37%** **None**, use is steady throughout the year
- **4%** Not sure

78% Have **1-2** ***separate*** **business locations** in NS

36.2 ***years*** is the ***average age*** of main building



Every insight tells a story.

NARRATIVE RESEARCH

Nova Scotia Power
Time Variable Pricing Report
Residential Overall

June 2021

Prepared for:

Nova Scotia POWER
An Emera Company

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NARRATIVE RESEARCH

Objectives and Methodology

Objectives and Methodology

The following report provides the results of the first phase of research for the ***2021 Time Variable Pricing Study*** on behalf of Nova Scotia Power. Specifically, this version of the report includes only the results of the residential online survey, as the online survey with business customers is currently ongoing. The purpose of this first phase of research is to better understand customer perceptions regarding the proposed Time Variable Pricing rate plans, namely *Time of Use* and *Critical Peak Pricing*. Results of this survey will be used in subsequent phases of research, as well as assisting Nova Scotia Power in the development of their pilot program.

Specifically, key objectives of this research phase include:

- *Understanding business and residential customers' interest in TOU and CPP structures, including reactions to the concept in general as well as reactions to potential levels of cost savings;*
- *Determining customers' willingness to participate in either TOU or CPP;* and
- *Gauge general customer perceptions of the proposed pricing structures.*

A total of 7,675 residential online surveys were collected, and on average, participants took 27 minutes to complete. In total, 42,630 residential customers were invited the survey resulting in a combined response rate of 18%. Customers invited to participate in the research were identified in multiple ways. Specifically, customers who participated in the previous 2019 End Use study were invited to participate as it would allow results of the previous survey to be imported and analyzed for context. Additionally, the entirety of the Nova Scotia Power Customer Advisory Panel was invited to participate, and a random subset of customers from Nova Scotia Power's customer database were also invited.

Surveys were collected between June 4th and 14th, 2021.

Throughout this report, demographic customer analysis is provided. In an effort to identify notable differences between customer subgroups, differences of ten percentage points or more are included in the textual analysis. That said, given the very large sample sizes for various customer demographics, additional differences can be identified within the provided data tables but are not included in the textual analysis given space limitations.

NARRATIVE RESEARCH

Summary of Key Findings

Summary of Key Findings

The following highlights are derived from the residential results from Phase 1 of the 2021 Time Variable Pricing Study:

Of note, most customers are currently unfamiliar with the existing Time of Use plan that is offered by Nova Scotia Power, a result that is perhaps not surprising as only a small proportion of customers are on this rate plan. That said, customers express a ***high degree of interest in a Time of Use plan***, with two-thirds expressing interest in participating if it became available. When comparing the two rate plans individually, ***Time of Use garners much higher interest than Critical Peak Pricing***. While ***potential savings*** is most often cited as the aspect customers like most about Time of Use, customers most commonly express ***concern that electricity will cost more when they use it most*** in terms of what they most dislike.

MyAccount

The vast majority of customers that participated in this online survey were e-billing customers. It is positive to note that e-bill customers express a high degree of satisfaction with the MyAccount experience, and most use it at least a few times a year. Most commonly, customers will log in when they get their bill, and few log in more often than once a month. In general, customers are more likely to indicate they review their entire bill thoroughly as opposed to just looking at the amount due.

Usage

Among participants who completed the online survey, ***electricity*** is the most common energy source used for their home heat, as used by three-quarters, while ***oil*** is used by four in ten and ***wood*** by one-quarter. In terms of temperature control, only one in ten customers have a ***smart thermostat***, while three in ten have a ***programmable thermostat***. Customers with electric heat that do not currently own a smart thermostat express relatively moderate likelihood of installing a smart thermostat in the next three years, with three in ten indicating being highly likely. Among customers who have installed a smart thermostat, the primary reasons for doing so was to ***save on electricity/heating costs***, and to make their ***heating more efficient***. Among those who are interested in installing a smart thermostat, their interest is primarily related to ***saving electricity***. Not surprisingly, the majority of customers with electric heat, heat their home between 19 and 22 degrees Celsius in the winter, and the majority of customers on electric heat also reduce their temperature when not at home or at night time.

Two-thirds of customers ***do not have any smart appliances*** in their home, while one-quarter have ***some*** smart appliances. Two thirds of customers indicate that they have an electric water heater in their home, while only two percent have a heat pump water heater. In terms of large appliances, most have an electric clothes dryer in their home, while a small majority also have a stand alone freezer and ceiling/window fans. Four in ten customers also express having a dehumidifier in their home.

Summary of Key Findings (continued)

Rate Information and Time Variable Pricing

Three-quarters of customers indicate being billed using the ***Standard Rate***, while just fewer than one in ten indicate being on ***Time of Use*** billing and three percent are on ***Net Metering***. Of note, more than one in ten customers noted being ***unsure*** of what rate they are on. Overall, familiarity with the existing Time of Use rate plan is low, with only one-quarter of customers expressing being familiar. Despite relatively low familiarity, more than one-half of customers express a high level of interest in the proposed Time Variable Pricing plan following a brief description. What's more, following a lengthier description with possible savings estimates, two-thirds of customers expressed a high level of interest in participating in a Time Variable Pricing plan if it became available.

Time of Use

Looking at the Time of Use plan specifically, one-half of customers express a high likelihood of participating in such a plan if it became available. Most commonly, customers like that the concept offers them ***cheaper rates and a chance to save money***, that ***using power during off peak hours will be better for the environment***, and ***they will have more control over their electricity bill.*** Meanwhile, the greatest dislike or concern about the plan is that ***electricity will cost more during times when they use it most.***

Critical Peak Pricing

Looking at the Critical Peak Pricing plan specifically, one-third of customers express a high likelihood of participating in such a plan if it became available. Most commonly, customers like that the concept offers them ***a chance to save money, lower rates for most of the year, that using power during off peak hours is better for the environment,*** and ***they will have more control over their bill.*** That said, three in ten customers indicate, unaided, there is ***nothing*** that they like about the plan. Conversely, the greatest dislikes with this plan include ***electricity costing more when they use it most***, ***that in order to save money they would have to change their behaviour***, and ***they are not able to change their behaviour***.

Preferred Rate Plan

Of the two concepts evaluated, ***Time of Use*** garners greater preference among customers. Overall, four in ten indicate a preference for ***Time of Use*** when asked to choose, while one in ten prefer the ***Critical Peak Pricing*** option. Just over one in ten indicate they are ***both of equal interest***, while two in ten are ***not interested in either*** plan. Just over one in ten are looking to ***learn more*** about the plans before making a decision, and one in ten are ***unsure***.

Summary of Key Findings (continued)

Preferred Rate Plan (Continued)

Among those who prefer the Time of Use plan, the predominant reason is because it is ***easier to implement and better fits their schedule***. Meanwhile, those who prefer the Critical Peak Pricing concept most commonly mention it is because of the ***potential cost savings and lower rates throughout the year***. Among those who are not interested in either plan, a variety of reasons are mentioned as to why, with the most common including ***that it provides minimal benefits/savings, bills will be higher,*** and they ***prefer their current plan***. Of those who are looking to learn more before making a decision, they most commonly would like to know a ***cost breakdown of each option to understand how each could save them money.***

In terms of potential bill savings to make the programs worthwhile for them, customers are looking for high annual savings. ***On average, customers are looking to save more than $300 per year overall,*** though it is important to note that a majority of those interested in either program would find the program worthwhile if they saved less than $300 a year, and two in ten or more would be happy with the program if they saw savings up to $100. Not surprisingly, those who are not interested in either plan would like to see greater savings than those who expressed a clear preference for one of the programs.

When receiving updates and information regarding the program, ***email*** is the preferred method of communication for the majority of customers. Given the large proportion of customers who participated in the survey that are on e-billing, however, it is important to note that ***mail*** is a common mention among customers on paper billing.

NARRATIVE
RESEARCH

Detailed Analysis

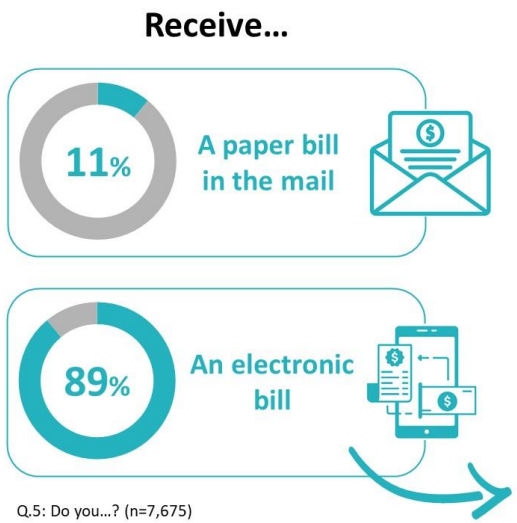
Billing Experience

The vast majority of customers surveyed are on e-billing and express a high level of satisfaction with the MyAccount experience.

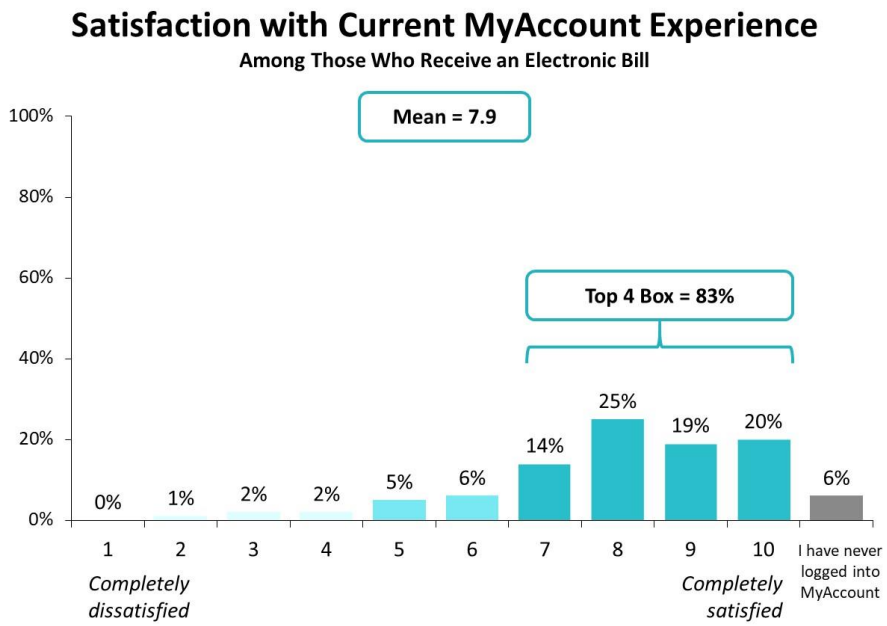
It is not surprising that a majority of those surveyed are on e-billing as the survey was administered online and could only be delivered to customers with an email address on file.

E-billing is more common among younger customers. (Table 5)

Top two box satisfaction (scores of 9 and 10) with the current MyAccount experience is highest among customers aged 55 and older, lower income earners. (Table 6)



Q.5: Do you…? (n=7,675)



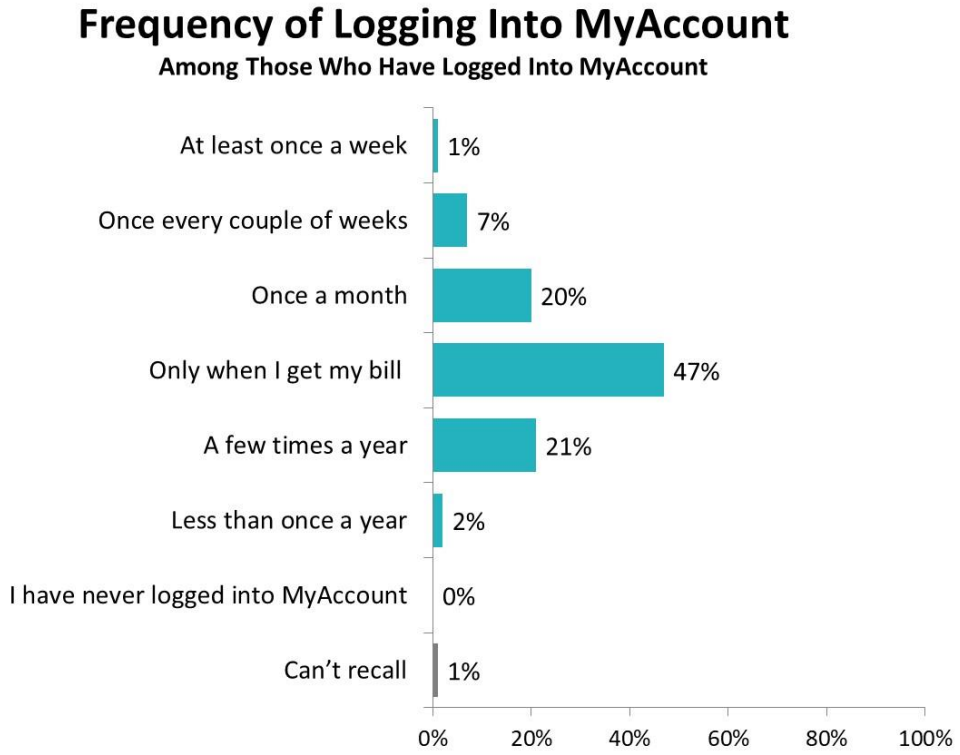
Q.6: **[IF RECEIVE ELECTRONIC BILL IN Q.5]** By having signed up for electronic billing, you have access to an online MyAccount profile. How satisfied are you with the current MyAccount experience? (n=6,803) *Note: 'I have never logged into MyAccount' is excluded from the box score and mean.*

MyAccount

Most commonly, customers only log into their MyAccount when they get their bill.

Nearly one-half of e-billing customers indicate they only log into MyAccount when they receive their bill every two months. Meanwhile, two in ten log in ***once a month,*** while a similar proportion log in ***a few times a year***.

Results are highly consistent across customer subgroups (Table 7)



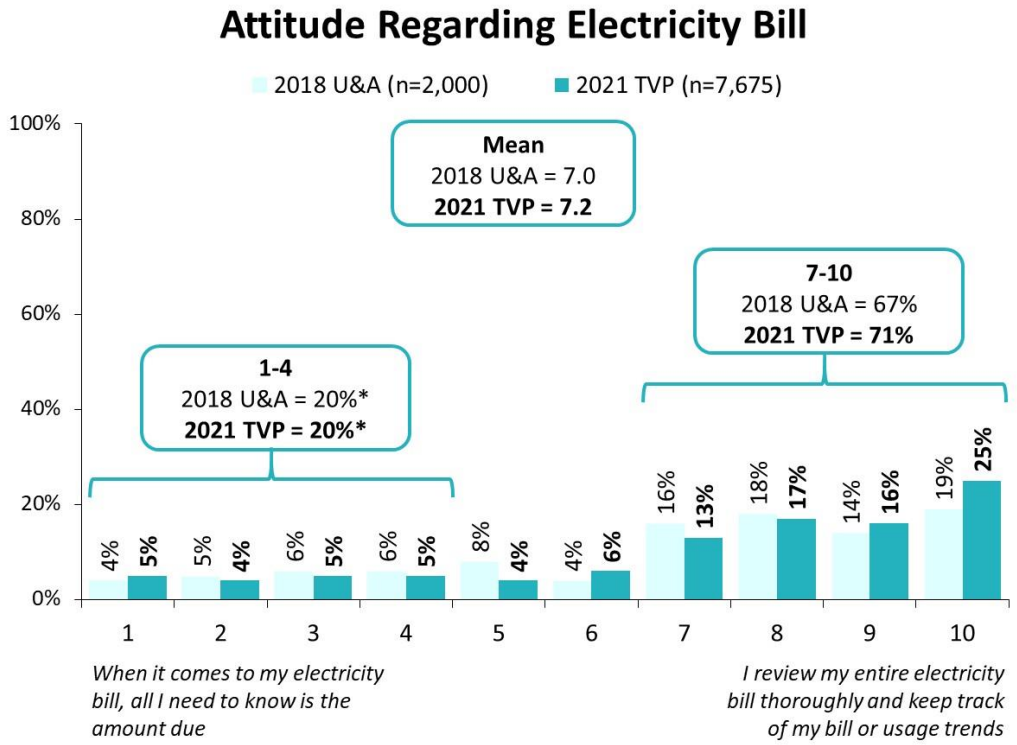
Q.7: **[IF HAVE LOGGED INTO ACCOUNT IN Q.6]** How often do you log into MyAccount. (n=6,369)

Electricity Bill

The majority of customers are more likely to review their bill thoroughly and keep track of trends, as opposed to simply paying the amount owed.

Customers were next presented a sliding scale and asked where their opinion lies between two statements. The majority of customers (71%) more closely align with the statement ***I review my entire electricity bill thoroughly and keep track of my bill or usage trends***, while two in ten (20%) more closely align with the statement ***when it comes to my electricity bill, all I need to know is the amount due.*** The question was previously asked the 2018 Usage and Attitudes (U&A) study and results remain largely unchanged.

Across demographics, older customers, and those who live in something other than a condo or apartment, are more likely to provide scores of seven to ten. (Table 8)



Q.8: For the following statement, please indicate where your opinion lies by moving the slider along the line. **Due to rounding.*

NARRATIVE RESEARCH

Communications

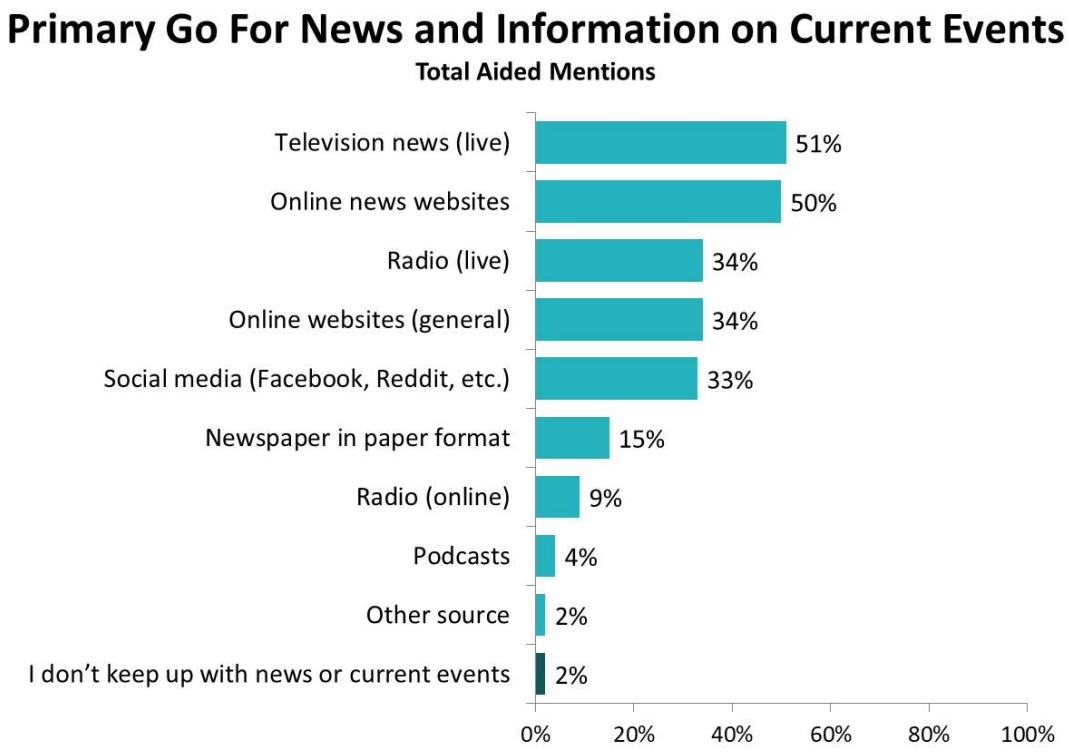
Sources for Current Events

Television and online news are customers' two go-to sources for news and information on current events.

For approximately one-half of customers each, ***television news (live)*** and ***online news websites*** are the most commonly mentioned primary sources for up to date news and information on current events. Meanwhile, one-third each mention ***live radio, online websites,*** and ***social media. Newspapers, online radio,*** and ***podcasts*** are much less commonly relied upon. Of note, totals sum to greater than 100 percent as customers were able to select multiple sources.

Mentions of live television news are notably higher among those aged 55 and older, paper billing customers, customers living in single family homes, duplexes, and mobile homes, and households with fewer people.

Meanwhile, online news is more commonly relied upon by customers with high household incomes, those not living in a mobile home, and e-billing customers. Mentions of social media are notably higher among women, customers under the age of 35, e-billing customers, and those with three or more people living in their household. (Table 9)



Q.9: Where do you primarily go for news and information on current events? (n=7,664) *Note: This question was optional.*

NARRATIVE RESEARCH

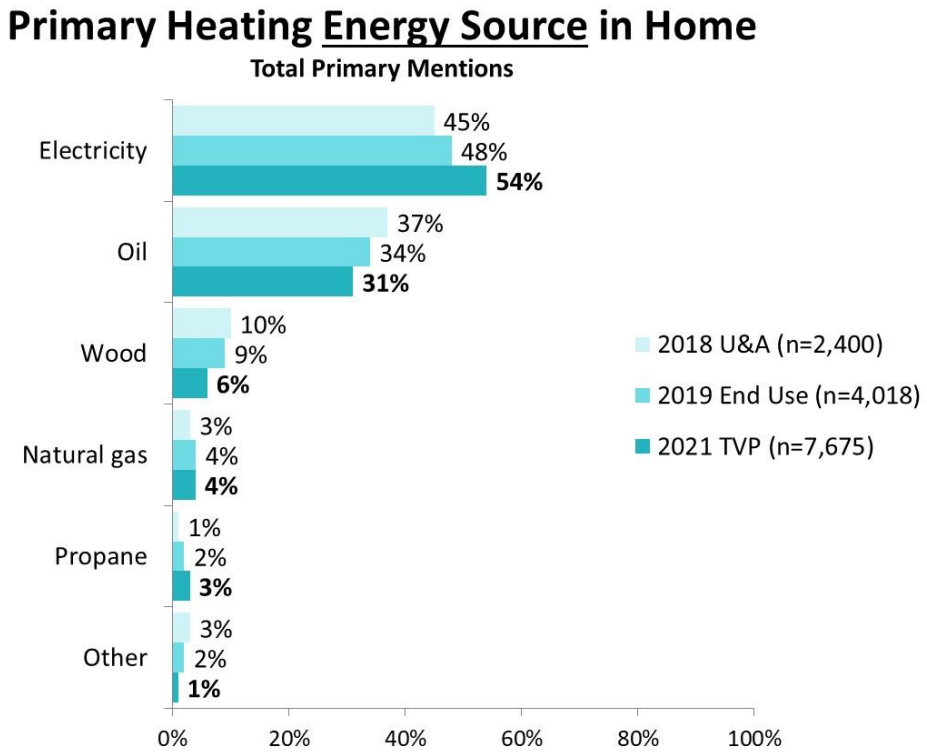
Usage

Primary Heat Source

More than one-half of customers use electric heat as their primary heat source in their home, while three in ten use oil.

This same question was posed in the previous 2019 End Use survey and 2018 U&A survey with results being relatively consistent between the three surveys.

Customers living in mobile homes are most likely to have electricity be their homes primary heat source. Meanwhile, primary heat sources are relatively similar across other customer demographics. (Table 10)



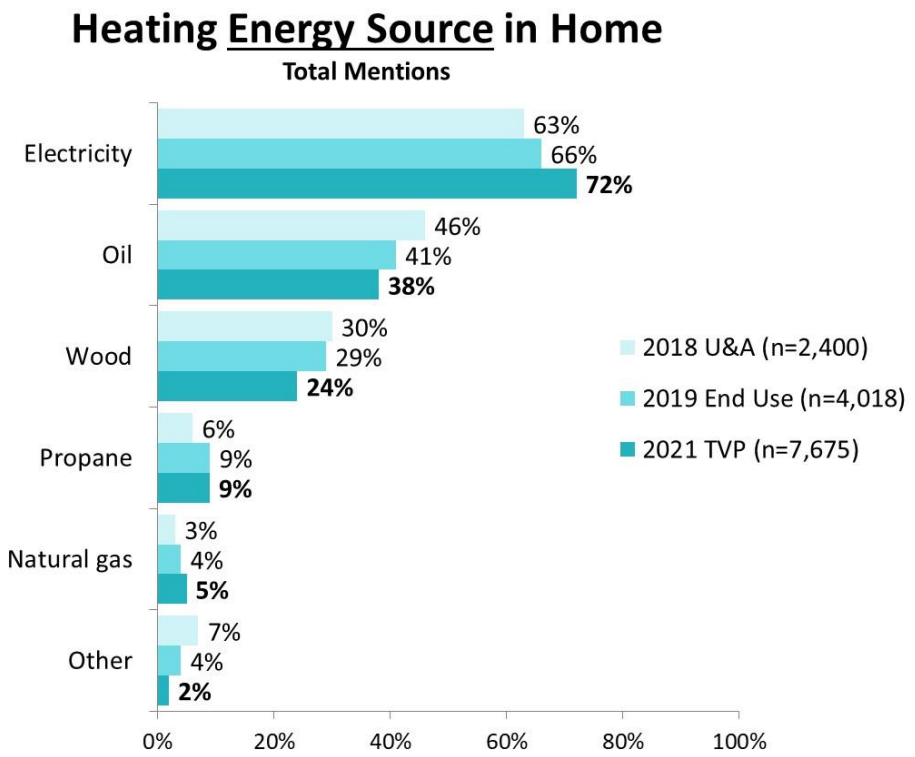
Q.10: What are the sources of heat in your home?

Home Heating Energy Sources

In terms of total heat sources customers have in their home, electricity is used by nearly three-quarters of customers, while oil is used by four in ten customers.

While only the primary heat source for six percent of customers, one-quarter of customers overall use wood as a heat source in their home (as either a primary or supplementary heat source).

Having wood as a heat source is more common among rural customers. Meanwhile, electric heat is much more common among houses built before 1985, while oil heat is more common among homes built in 1985 or later. (Table 10)

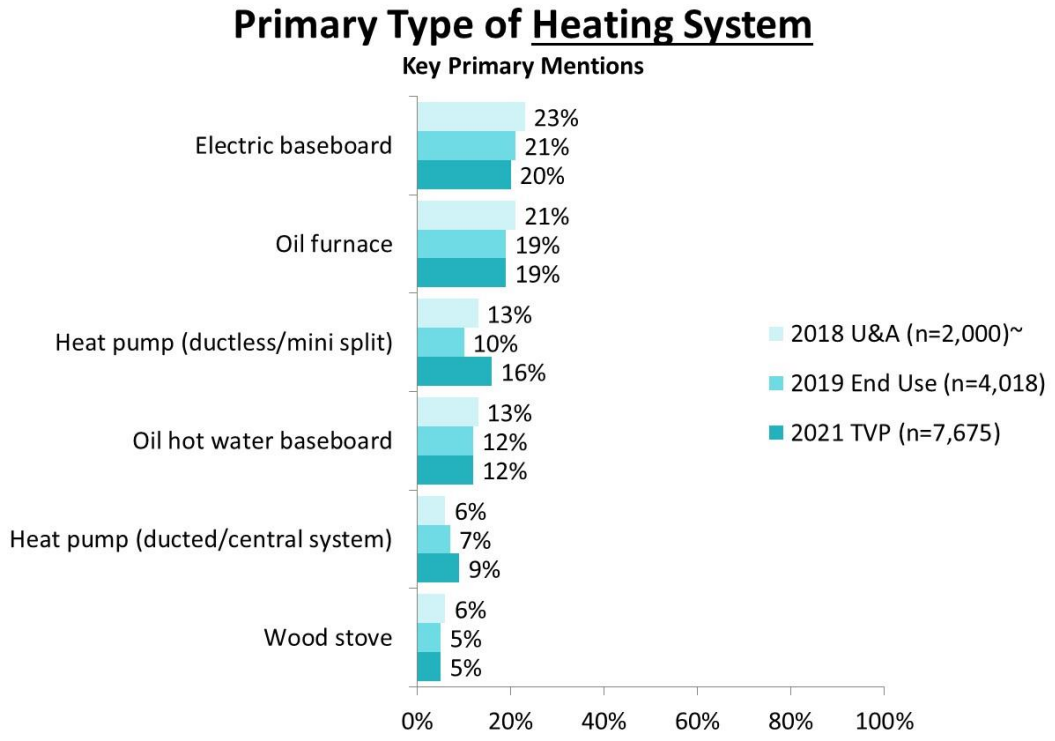


Q.10: What are the sources of heat in your home?

Primary Heating System

In terms of heating systems, electric baseboard, oil furnace, and heat pumps are most common.

More specifically, two in ten each use ***electric baseboards*** or an ***oil furnace*** as their primary heating system, while just fewer than two in ten use a ***heat pump***. Other heating systems are comparatively less common. Results are consistent with results obtained during the 2018 U&A and 2019 End Use studies. (Table 10)

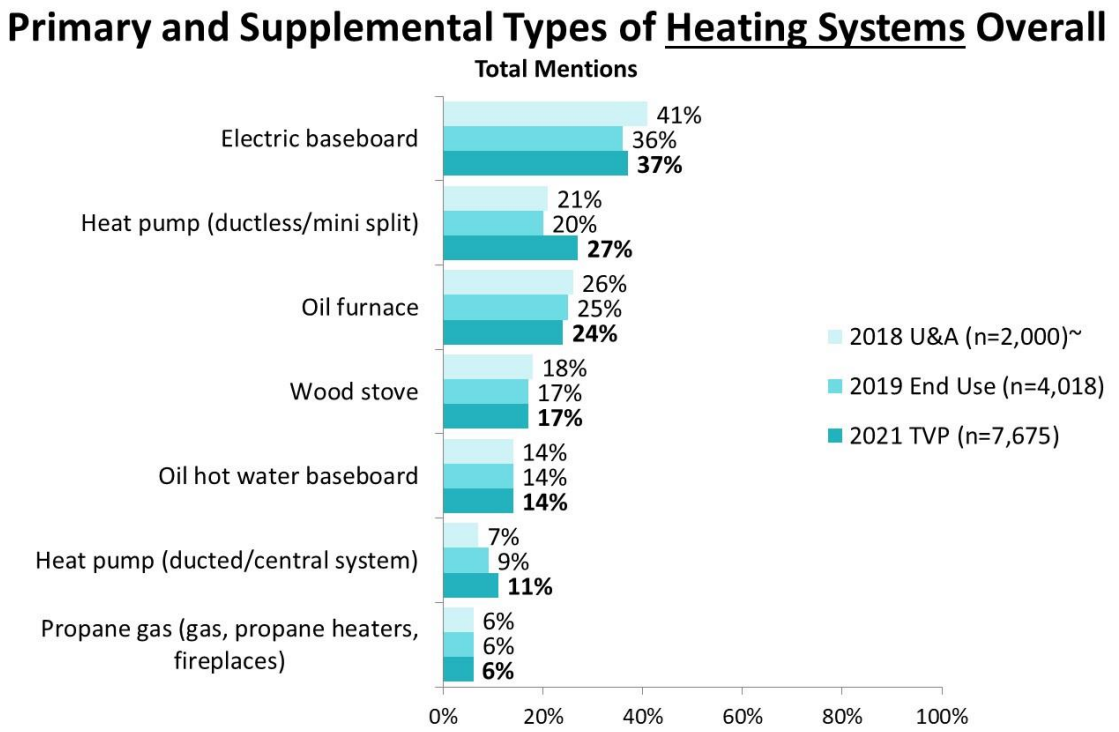


Q.10: What are the sources of heat in your home? *~Note: In the 2018 U&A survey, this question was only asked on the Online survey (excluded from the Telephone survey).*

Home Heating Systems (Overall)

Across all heating systems that customers have in their homes, electric baseboards are most common, with heat pumps narrowly surpassing oil furnaces.

As many customers have multiple heating systems within their homes (e.g., a primary system and a supplementary back-up system), the graph to the right displays the total incidence of heating systems customers have. Results are similar to what was obtained in the 2018 and 2019 studies, although ***heat pumps*** are slightly more commonly mentioned in the current study. (Table 10)



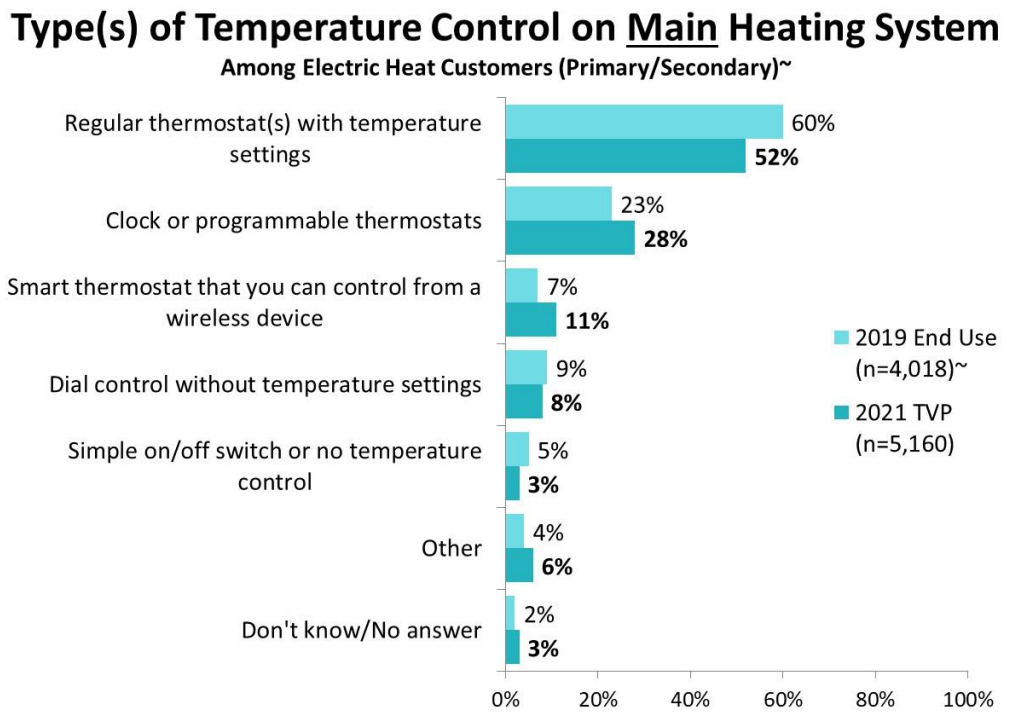
Q.10: What are the sources of heat in your home? *~Note: In the 2018 U&A survey, this question was only asked on the Online survey (excluded from the Telephone survey).*

Temperature Control Systems

One-half of customers have a regular thermostat for their main heating system, while three in ten have a programmable thermostat.

Smart thermostats are uncommon among customers, only being mentioned by one in ten (11%). Results overall are similar to what was obtained in 2019, although it is important to note that in the 2019 End Use study the question was posed to everyone, while in 2021 it was only posed to customers with electric heat. This is due to the fact that thermostat type would only impact electricity bills of those with electric heat, an important input for the TVP rate plans.

Smart thermostats are more common among customers with a heat pump. (Table 11)



Q.11: **[IF ELECTRIC HEAT CUSTOMERS (PRIMARY/SECONDARY)]** What type(s) of temperature control does your main heating system have? *~Note: In the 2019 End Use survey, this question was asked to everyone. Note: In the 2021 TVP survey, some respondents were not asked this question due to upcoding in Q.10.*

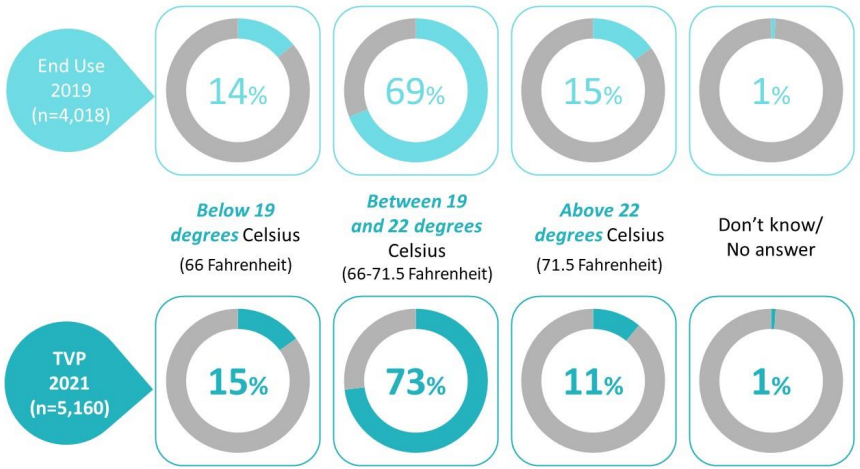
Heating Behaviours

The majority of customers keep their homes between 19 and 22 Celsius in the winter months, and the majority reduce the temperature when they aren't at home or at night.

Conversely, one in six keep their home's temperature below 19 degrees, while one in ten keep the heat above 22 degrees. Compared to the 2019 End Use study, results are consistent. Once again, the current study only posed this question to customers with electric heat.

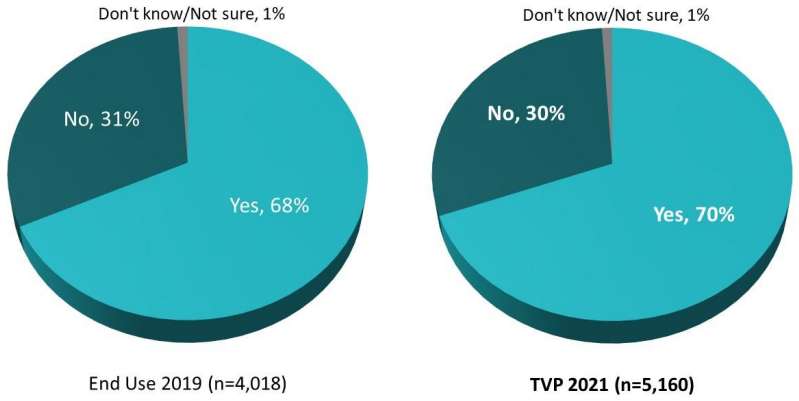
Across demographics, customers with heat pumps are more likely to heat their home between 19 and 22 degrees, while those without a heat pump are more likely to keep temperatures below 19. Reducing the temperature while away or at night is higher among customers not primarily using electric heat. (Tables 12 and 13)

Home's Typical Room Temperature in Winter Months
Among Electric Heat Customers (Primary/Secondary)~



Q.12: **[IF ELECTRIC HEAT CUSTOMERS (PRIMARY/SECONDARY)]** Which of the following best describes your home's typical room temperature in the winter months? *~Note: In the 2019 End Use survey, this question was asked to everyone. Note: In the 2021 TVP survey, some respondents were not asked this question due to upcoding in Q.10.*

Reduce Temperature in Home When Not at Home or at Night Time
Among Electric Heat Customers (Primary/Secondary)~



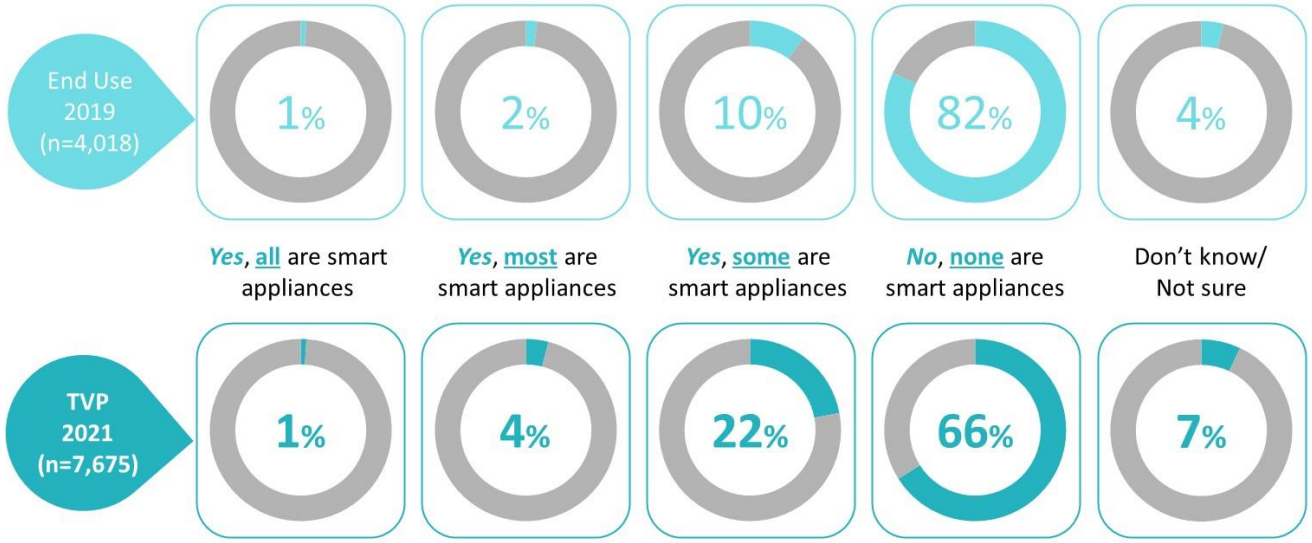
Q.13: **[IF ELECTRIC HEAT CUSTOMERS (PRIMARY/SECONDARY)]** Do you reduce the temperature in your home when you're not at home or at night time? *~Note: In the 2019 End Use survey, this question was asked to everyone. Note: In the 2021 TVP survey, some respondents were not asked this question due to upcoding in Q.10.*

Smart Appliances

Two-thirds of customers do not have any form of smart appliances in their home, while one-quarter have at least some smart appliances.

Only one percent of customers have ***entirely*** smart appliances, and only four percent have ***mostly*** smart appliances. Customers with a smart thermostat are twice as likely to have at least some of their appliances be equipped with smart controls. (Table 14)

Smart Appliances in Home



Q.14: As you may or may not know, some electronic devices and appliances can include or be equipped with 'smart controls'. These controls can help you manage your energy usage and offer many features, including the ability to only power a device when you need it. For example, you can program lights to turn on automatically, or turn your water heater on or off. Do you have any smart appliances in your home?

Likelihood of Installing Smart Thermostat

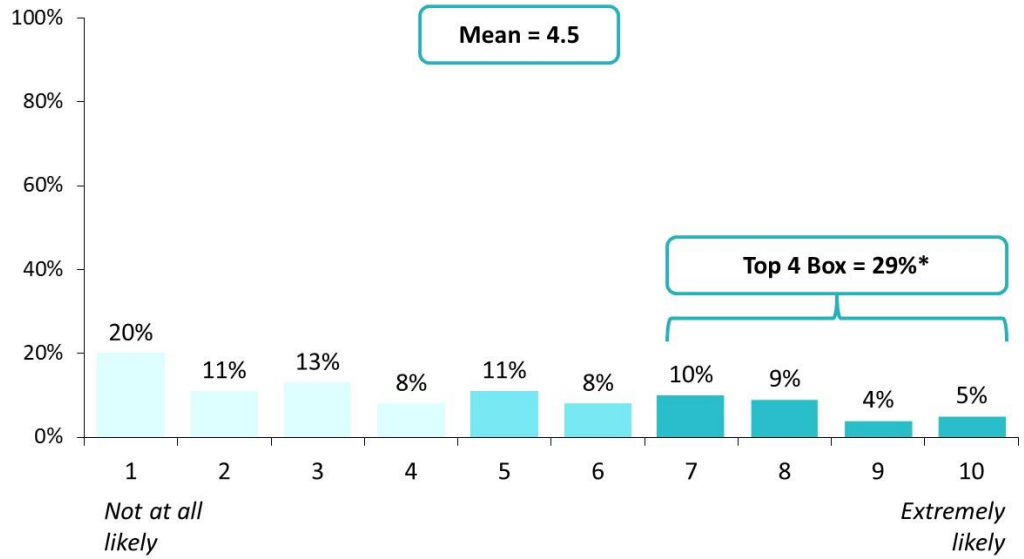
Among customers without a smart thermostat already installed, there is clear interest in installing one in the next three years.

More specifically, one-third of those without a smart thermostat express a high likelihood of installing a smart thermostat in the next three years. Although a minority, this result suggests that smart thermostats could see greater adoption in the near future.

Likelihood of installing a smart thermostat increases with household income and decreases with age. (Table 15)

Likelihood of Installing a Smart Thermostat in Home in the Next Three Years

Among Electric Heat Customers (Primary/Secondary) Who Do Not Have a Smart Thermostat



Q.15: **[IF ELECTRIC HEAT CUSTOMERS (PRIMARY/SECONDARY) AND DO NOT HAVE A SMART THERMOSTAT IN Q.11]** How likely are you to install a smart thermostat in your home in the next three years? (n=4,593) **Due to rounding. Note: Some respondents were not asked this question due to upcoding in Q.10.*

Reasons for Installing Smart Thermostat

The small proportion who have already installed a smart thermostat primarily did so to save on electricity, and to make their heating more efficient.

Other key mentions made by a small proportion of these customers each include that ***it came with their home***, they installed it ***to be more environmentally friendly***, and ***so that they have the latest technology***.

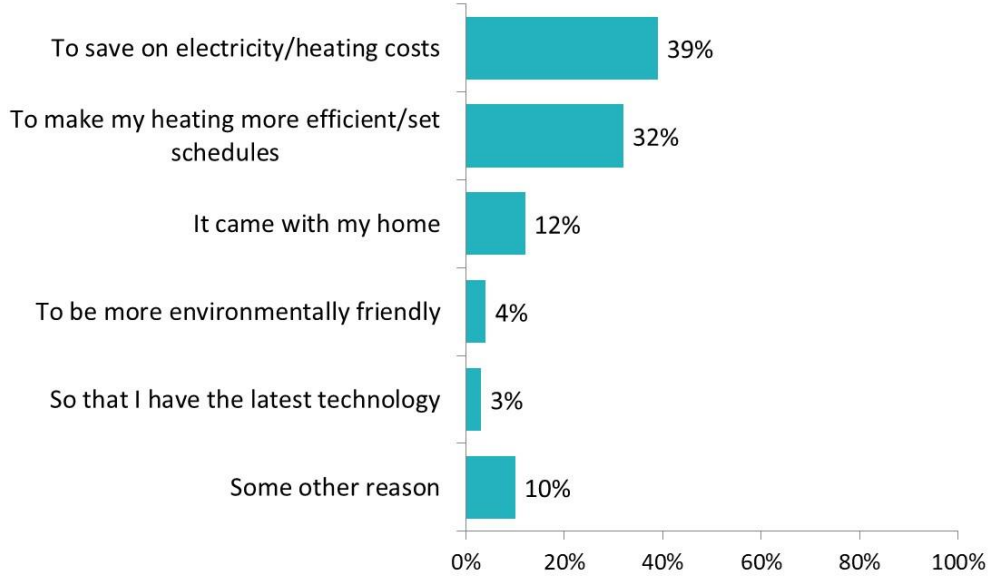
Caution should be taken when interpreting some customer demographic subgroups given small sample sizes. (Table 16)

11% *Use a smart thermostat to control their main heating system*

Primary Reason Installed Smart Thermostat in Home

Total Aided Mentions

Among Electric Heat Customers (Primary/Secondary) Who Have a Smart Thermostat



Q.16: **[IF ELECTRIC HEAT CUSTOMERS (PRIMARY/SECONDARY) AND HAVE SMART THERMOSTAT IN Q.11]** Thinking about the smart thermostat that you have installed in your home, please select the single most important reason as to why you installed it. (n=567) *Note: Some respondents were not asked this question due to upcoding in Q.10.*

Reason for Interest in Installing Smart Thermostat

Among customers expressing a high likelihood of installing a smart thermostat, interest is primarily related to electricity savings.

Among customers interested in installing a smart thermostat, and who have electric heat in their home. It is perhaps not surprising that the key reason to install a smart thermostat is to save on electricity, as more efficient heating would directly impact their electricity bill.

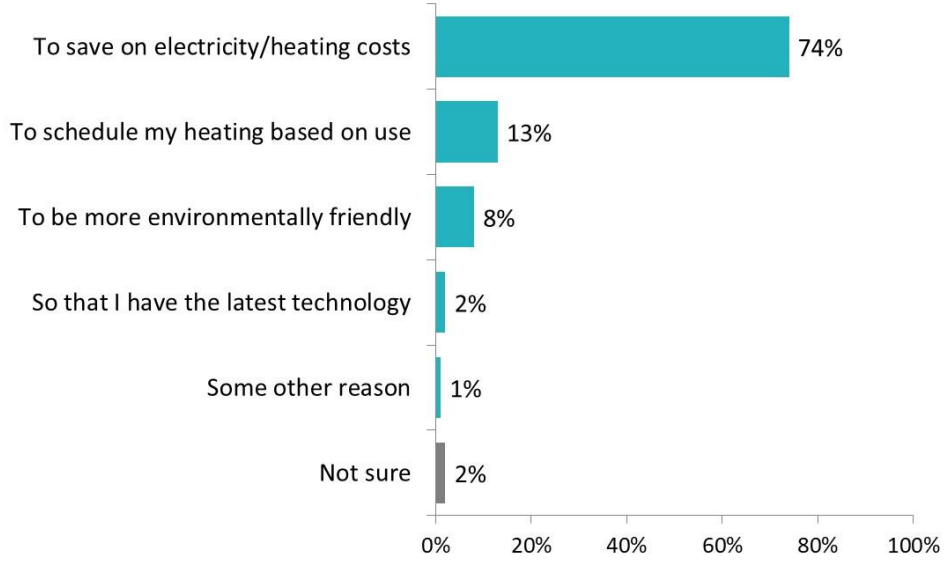
Mentions of wanting to save on their electricity costs are elevated among customers aged 35 and older, while it is also highest among customers living in mobile homes. Perhaps not surprising, those who would require a greater proportion of bill savings to participate in one of the TVP programs, are also more likely to mention wanting to install a smart thermostat for savings on their electricity.

37% Likely to install a smart thermostat in home in next three years (rating of 6-10)

Primary Reason Interested in Installing Smart Thermostat

Total Aided Mentions

Among Electric Heat Customers (Primary/Secondary) Who Rated Their Likelihood of Installing a Smart Thermostat in Home in Next Three Years 6 or Higher



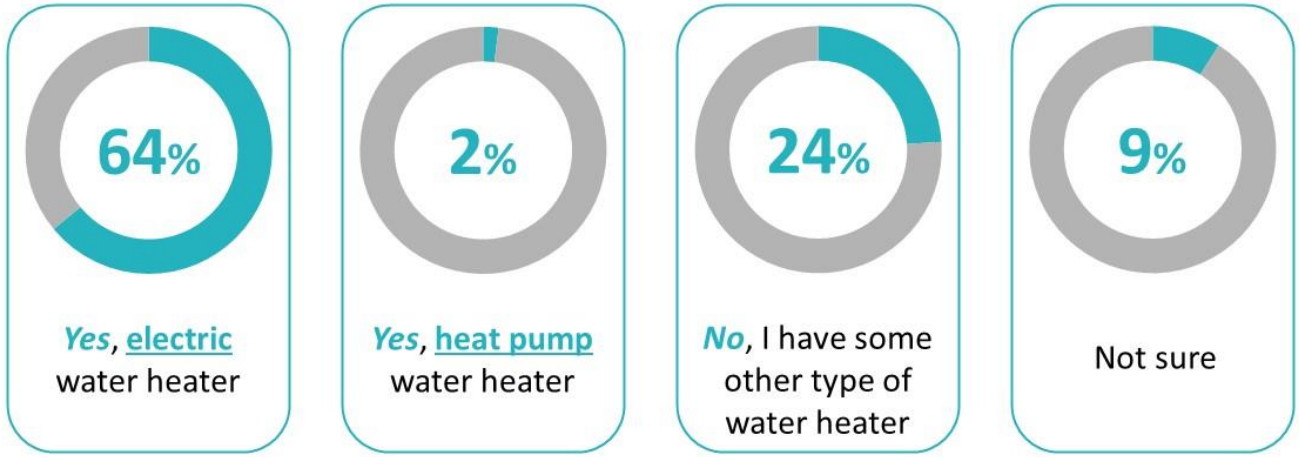
Q.17: **[IF ELECTRIC HEAT CUSTOMERS (PRIMARY/SECONDARY) AND RATED 6 OR HIGHER IN Q.15]** What is the single most important reason why you are interested in installing a smart thermostat? (n=1,713) *Note: Some respondents were not asked this question due to upcoding in Q.10.*

Water Heater

Two thirds of customers have an electric water heater.

While electric water heaters are common, comparatively, heat pump water heaters are rare, only being used by two percent of customers. Meanwhile, one-quarter of customers use some other type of water heater. Not surprisingly, electric water heaters are most common among customers with electric heat. They are also more common among customers aged 35 and older, rural customers, and those living in something other than a condo/apartment. (Table 18)

Have an Electric or Heat Pump Water Heater



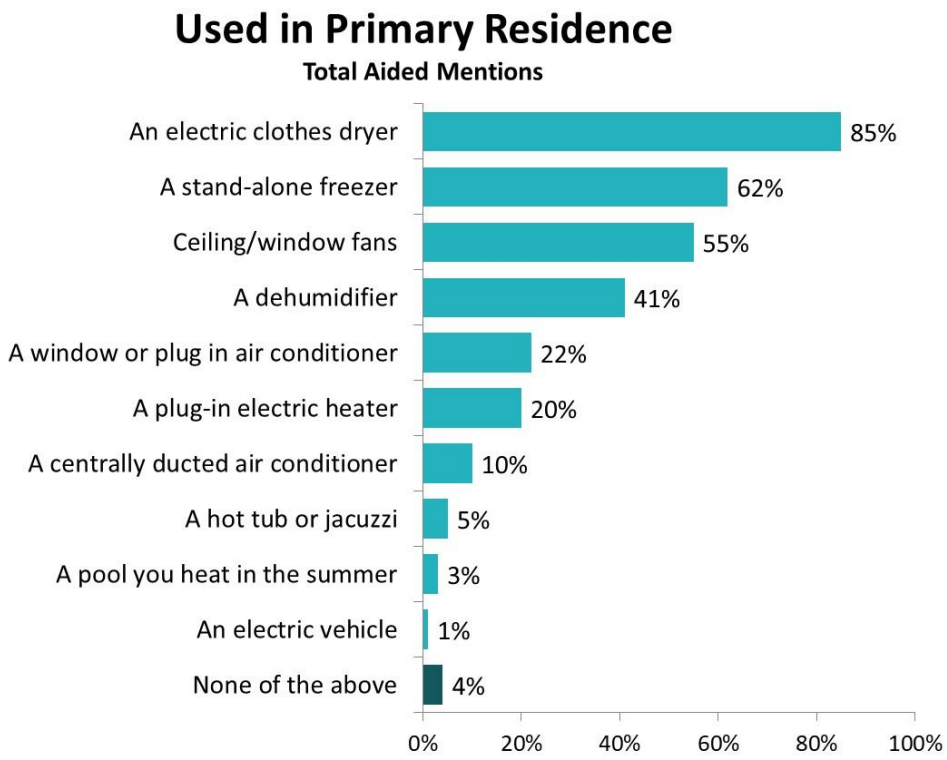
Q.18: Do you have an electric or heat pump water heater? (n=7,675)

Appliance Use

Customers were asked whether they use a variety of large appliances at their home.

The vast majority of customers indicate having an ***electric clothes dryer*** in their home, while more than one-half also indicate having ***a stand-alone freezer***, and ***ceiling/window fans***. Four in ten customers have a ***dehumidifier***, while other less common items include ***a window air conditioner, plug-in electric heater, centrally ducted air conditioner, hot tub/jacuzzi,*** and a ***pool***. One percent of customers indicate having ***an electric vehicle.***

Electric clothes dryers and stand-alone freezers are more common among customers with a heat pump. Those items, in addition to ceiling/window fans and a dehumidifier, are more common among customers aged 35 and older. Customers under the age of 55 are more likely to have a window air conditioner. (Table 19)



Q.19: Which of the following do you use **in your primary residence**? Select all that apply. (n=7,675)

NARRATIVE RESEARCH

Rate Information - General

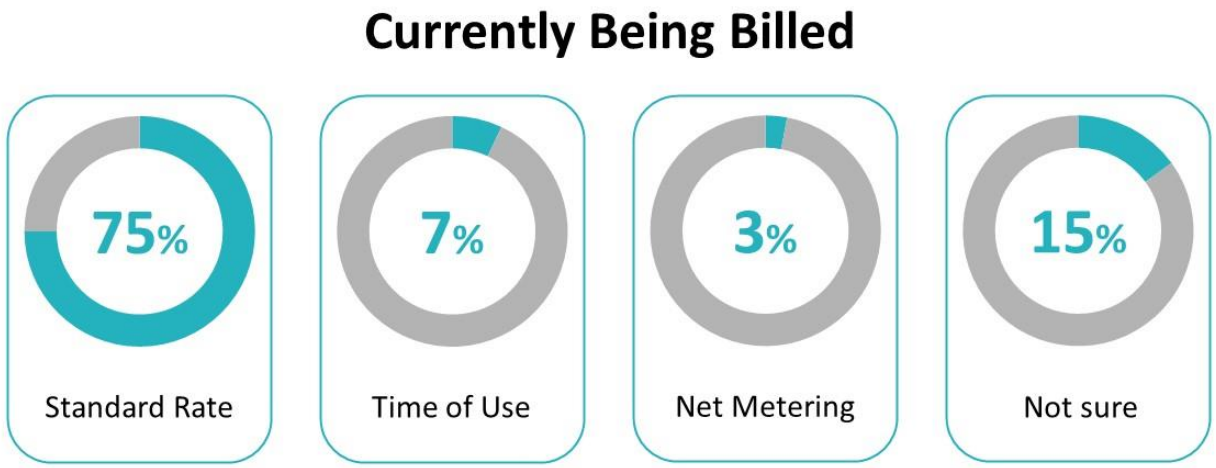
Rate Type

Not surprisingly, most customers indicate being billed using the standard rate, with Time of Use and Net Metering billing being much less common.

Of note, one in six customers were unsure which type of billing they were currently receiving. Younger customers, those living in condos/apartments, and customers who are least familiar with the existing Time of Use rate program are most likely to be ***unsure*** what type of billing they are on. (Table 20)

There are three ways Nova Scotia Power currently bills its residential customers:

Standard Rate per kilowatt hour – one price for electricity regardless of the time of day or season
Time of Use – different prices for three periods of the year, requires a thermal storage system such as in-floor electric heat or ETS unit.
Net Metering – for those who generate some or all of their own electricity, for example, from solar panels



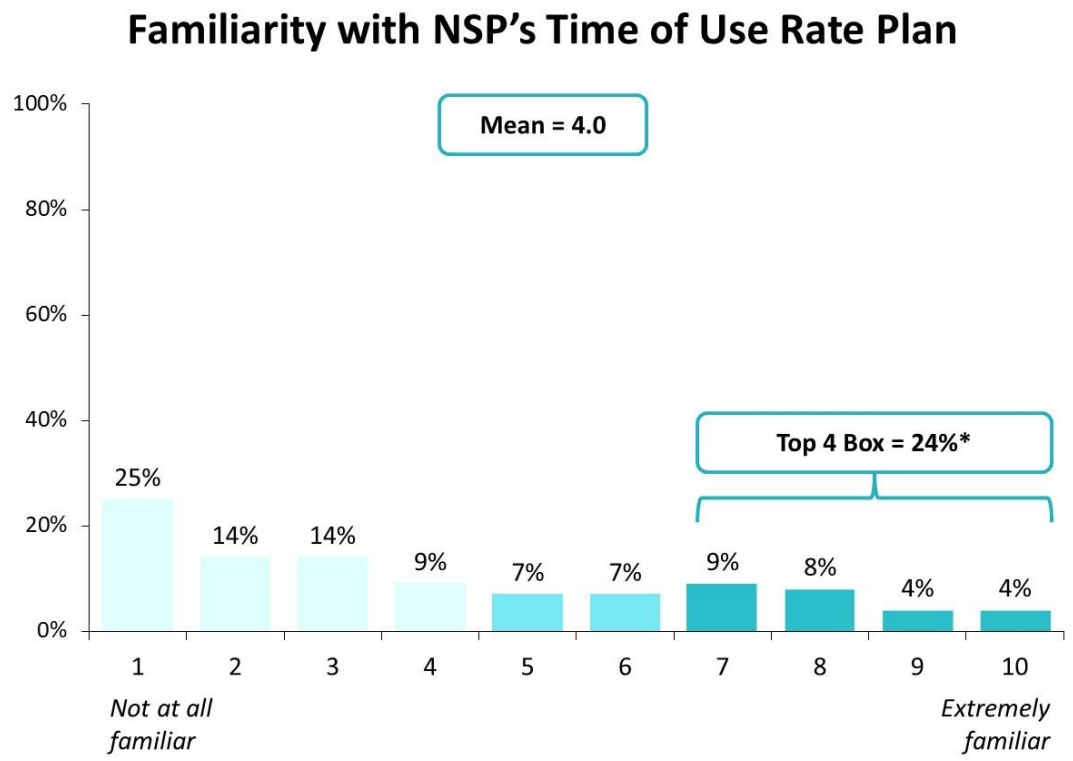
Q.20: How are you currently being billed? (n=7,675)

Familiarity with Time of Use

Customers overall express a low level of familiarity with the existing Time of Use plan.

Perhaps not surprising as few customers are on the Time of Use plan offered by Nova Scotia Power, customers overall express a relatively low level of familiarity with the rate plan. More specifically, one-quarter express a ***high*** familiarity, while an equal proportion express being ***not at all familiar*** (providing a rating of 1). The majority of customers (62%) express a ***low*** level of familiarity, providing scores of one to four on a ten point scale.

Familiarity is highest among customers who use electricity as their primary source of heat, while familiarity is also elevated among higher income earners, and men.



Q.21: How familiar are you with the ***Time of Use Rate Plan*** offered by Nova Scotia Power? (n=7,675) **Due to rounding.*

NARRATIVE RESEARCH

Rate Information

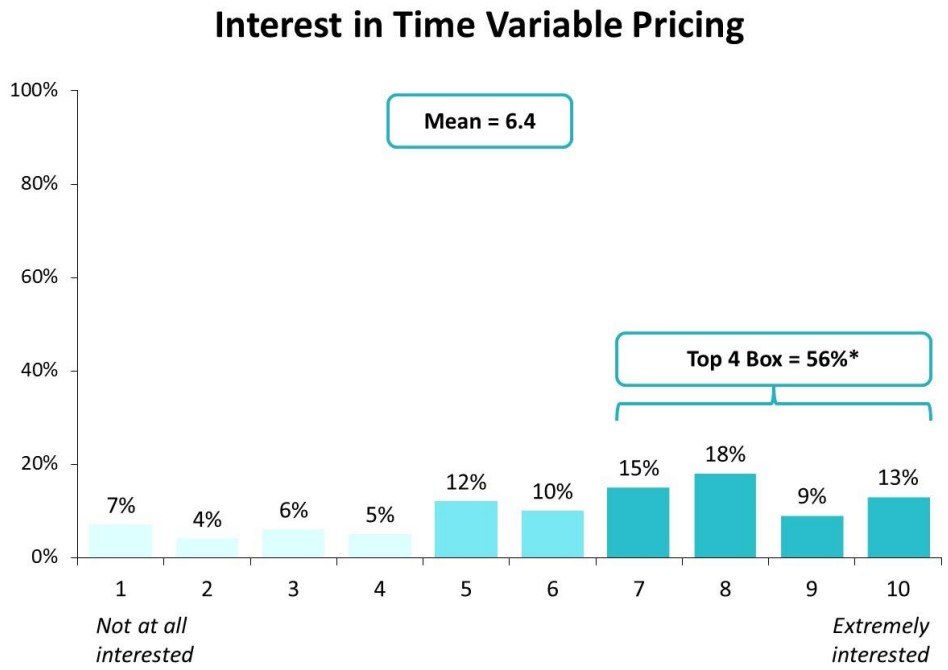
Interest in Time Variable Pricing

Following a brief description, there is a relatively high level of interest in the general concept of Time Variable Pricing, with more than one-half expressing interest.

Customers were provided with a brief description of the TVP concept and asked for their level of interest in participating in such a program. More than one-half provide a high level of interest, while only two in ten provide a low level of interest (22%).

Across customer demographics, interest increases with household income, and is also highest among customers who express a high level of familiarity with the existing Time of Use rate plan. Meanwhile, interest is lowest among customers who live in a condo/apartment. (Table 22)

Most Nova Scotia Power customers today are on a standard rate meaning they are charged a flat rate per kilowatt hour (kWh) for their daily energy use. Nova Scotia Power is considering offering two new rate options. For customers who choose to sign up, the price of electricity would vary between summer and winter months. In the winter, the price would fluctuate throughout the day. For example, the rates for electricity would be slightly higher when demand for electricity is higher (i.e., early morning and early evening hours). To offset the slightly higher winter rate, lower rates are applied during summer months.



Q.22: Overall, how interested would you be in participating in a program like this if it became available? (n=7,675) *Due to rounding.*

Interest in Participating in Time Variable Pricing

Following a more detailed description of the TVP program, customers express even greater interest.

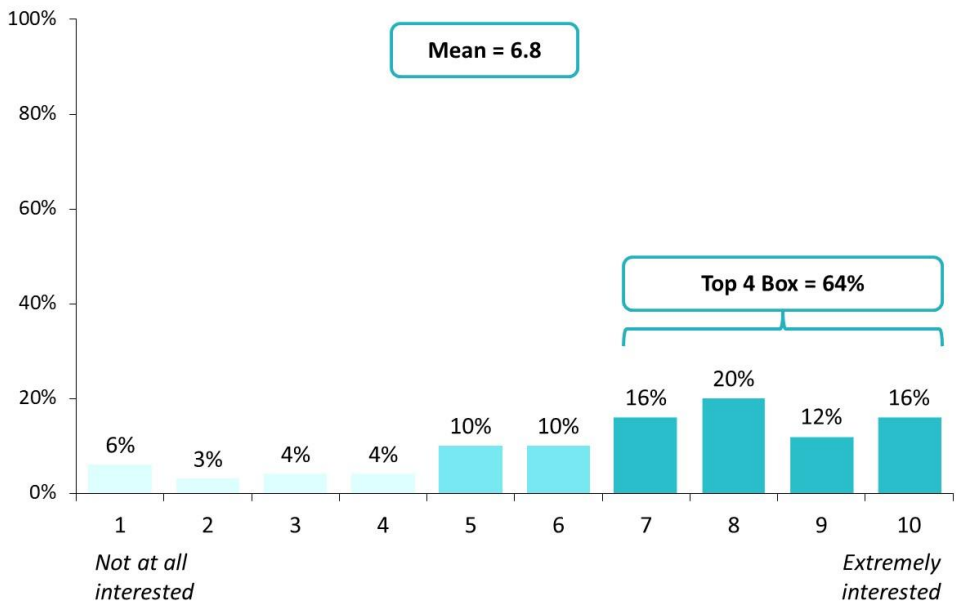
Following a more detailed description of the rate plan, including more information regarding potential savings if electricity consumption habits change, customers overall express a greater level of interest. Following this description, two-thirds express interest (compared with 56% following the shorter description). Meanwhile only 17% express disinterest (compared with 22%).

Interest is elevated among e-billing customers, high income households, and those with a high degree of familiarity with the existing Time of Use rate program. (Table 23)

Currently, the standard rate for electricity that most residential customers pay is $0.16/kWh. Under this new rate plan, you can achieve bill savings by changing when you use some of your electricity, especially major appliances such as oven, dryer, dishwasher, and dehumidifier. If you heat with electricity, you could also achieve savings by adjusting your heating (for example, changing your thermostat settings slightly or choosing to pre-heat your home when prices are lower).

[IF ELECTRIC HEAT CUSTOMER] For an average household that uses electric heat, this could result in savings in the range of $250 - $500 (or 4-10% of your bill amount) per year if you adjust when you use the majority of your electricity.

[IF NOT AN ELECTRIC HEAT CUSTOMER] For an average single-family home, this could result in savings of up to $100 - 200 (or 10-15% of your bill amount) per year if you adjust when you use some of your appliances. / For an average customer in an apartment, this could result in savings of up to $50 - $150 (or 10-15% of your bill amount) per year if you adjust when you use some of your appliances.



Q.23: In general, how interested would you be in participating in a program like this if it became available? (n=7,675)

NARRATIVE RESEARCH

Time of Use

Likelihood of Participating in Time of Use Plan

Customers were provided a description of the proposed Time of Use Plan, overall one-half express likelihood of participating in the new plan.

Overall, there is a great deal of interest in participating in the proposed Time of Use plan, with one-half of customers expressing a high likelihood of participating if it became available.

Of note, while presented as Option A and B in this report, customers were presented the Time of Use and Critical Peak Pricing in random order to prevent order bias in the results.

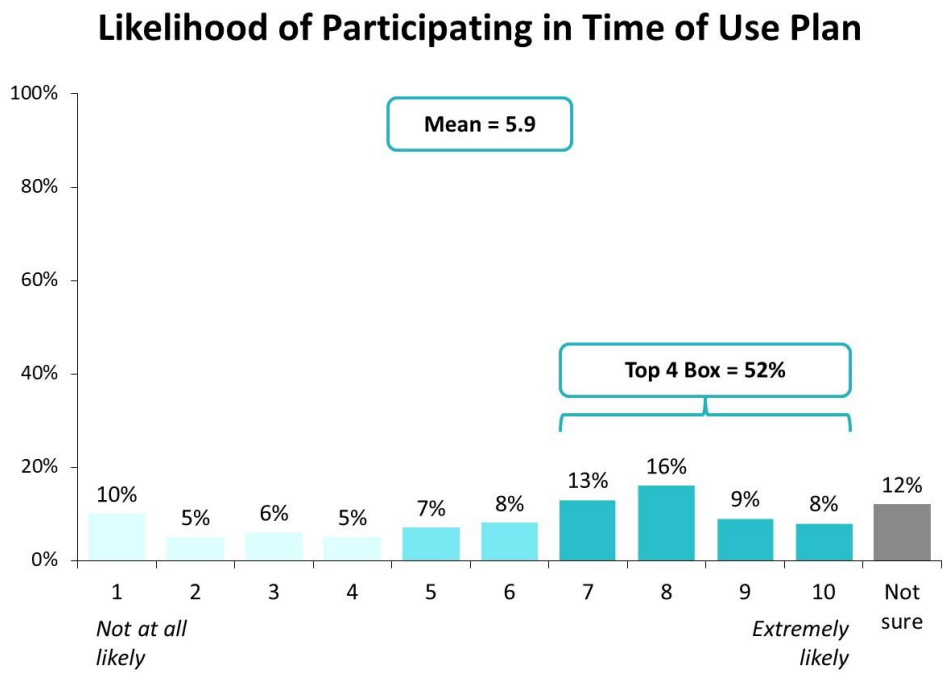
Overall, across customer demographics, likelihood of participating is similar. That said, customers who are most familiar with the existing Time of Use plan express greater likelihood of participating in the proposed Time of Use plan, as do customers living in townhouses.

Option A: *Time of Use*

With the Time of Use Plan, work days during winter months would be divided into peak and off-peak hours. Monday to Friday, from 7AM to 11AM and 5PM to 9PM is considered peak. Prices will be higher during the peak period hours to reflect the higher cost of providing energy during that period. The Time of Use Plan will allow customers to choose how and when they use electricity to take advantage of lower rates during off-peak periods. This could mean doing laundry on the weekend, and setting the dishwasher to clean overnight. If you heat with electricity you may adjust thermostat settings for a period of time, or use an alternate source of heat (if you have one). In exchange, the price for energy the remainder of the year would be less than the current standard rate.

For this plan, the cost of electricity during the peak hours would be $0.32/kWh (9% of the hours in the year) and would be $0.16/kWh during lower cost hours in the winter. The cost during 7 months of the year would be flat at $0.105/kWh.

For comparison, the current standard rate for electricity that most residential customers pay is $0.16/kWh.



Q.24: Based on this description, how likely would you be to participate in this type of plan? (n=7,675) *Note: Responses of 'Not sure' are excluded from all summary statistics.*

Likes and Dislikes of Time of Use

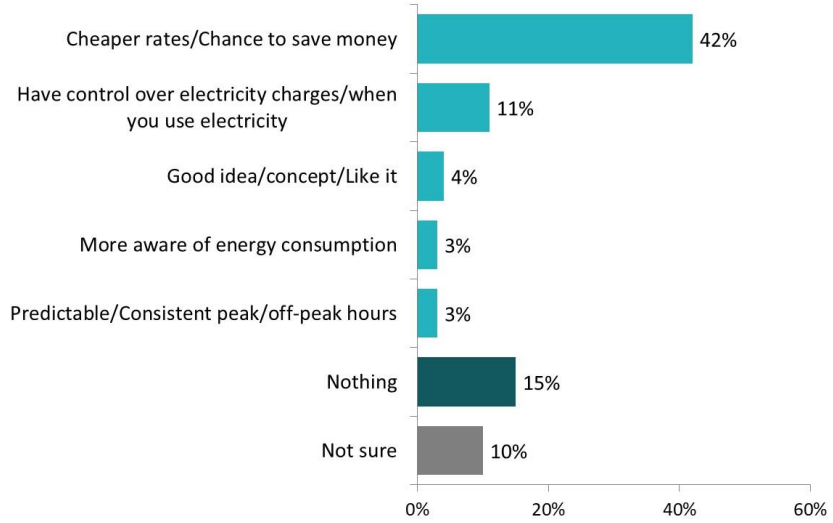
Customers most like the chance to save money on the Time of Use rate plan, while a variety of dislikes are mentioned by a small proportion each.

Unaided, customers most frequently mention liking the ***chance to save money*** on the Time of Use plan, while one in ten also mention liking the ability to ***have control over electricity charges***. In terms of dislikes, fewer than two in ten each mention that ***the peak rate is too high***, while one in ten or fewer mention disliking the need to ***change/control energy consumption***, that ***peak time is when they use electricity most***, among others.

Of note, results displayed on this page reflect verbatim comments of customers shared in an open-ended question that were then coded into categories.

Like About Time of Use Concept

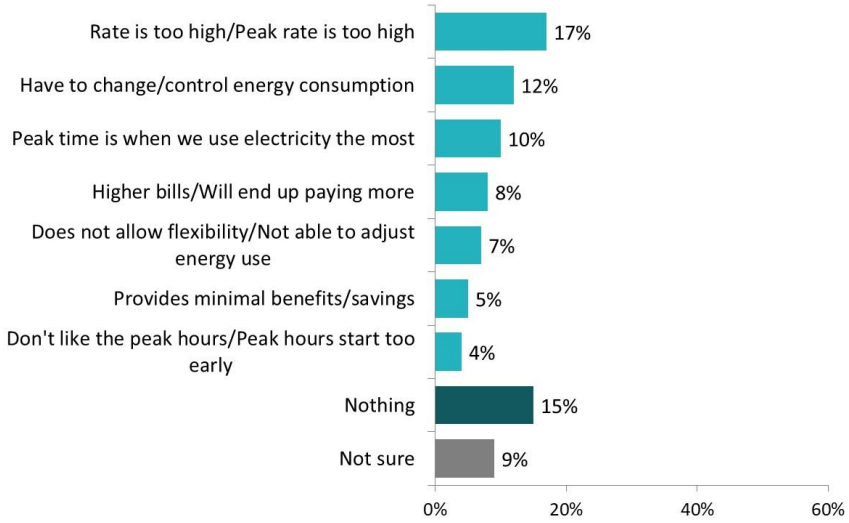
Key Unaided Mentions



Q.24a: What do you **like** about this concept? (n=500) *Note: 500 responses were chosen at random for coding for this question.*

Dislike About Time of Use Concept

Key Unaided Mentions

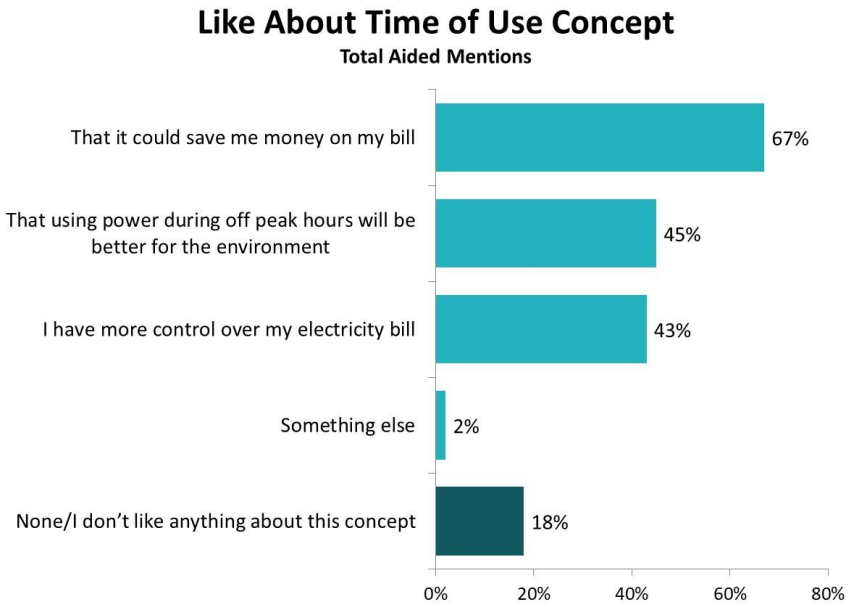


Q.24b: What do you **dislike** about this concept? (n=500) *Note: 500 responses were chosen at random for coding for this question.*

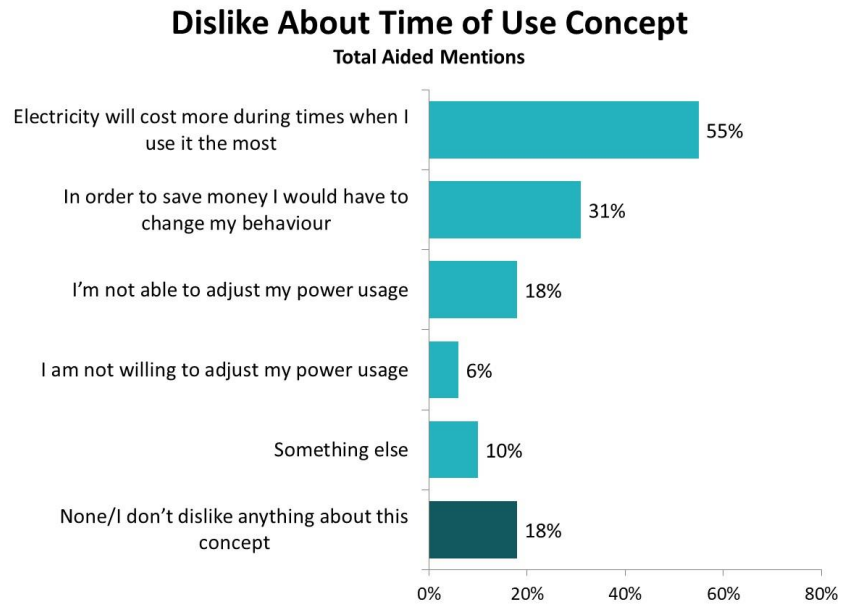
Likes and Dislikes of Time of Use (Continued)

Customers were once again asked what they liked and disliked about the Time of Use concept, this time prompted with options to choose from.

Most commonly, customers like ***that they could save money on their bill***, as selected by two-thirds, while just under one-half each also like ***that using power during off peak hours will be better for the environment*** and ***they will have more control over their electricity bill.*** Meanwhile, more than one-half of customers dislike that ***electricity will cost more during times when they need it most,*** and three in ten dislike that ***in order to save money they would need to change their behaviour.*** (Tables 24c and d)



Q.24c: And from the list below, what do you **like** about the concept? (n=7,675)



Q.24d: And from the list below, what do you **dislike** about the concept? (n=7,675)

NARRATIVE RESEARCH

Critical Peak Pricing

Likelihood of Participating in Critical Peak Pricing

Customers were provided a description of the proposed Critical Peak Pricing rate plan. Overall, one-third express a high likelihood of participating.

Overall, there is lesser interest in participating in the proposed Critical Peak Pricing plan when compared to the Time of Use plan. That said, one-third of customers still express a high likelihood of participating in the Critical Peak Pricing plan if it became available.

As noted, while presented as Option A and B in this report, customers were presented the Time of Use and Critical Peak Pricing in random order to prevent order bias in the results.

Likelihood of participating are consistent across customer demographics. (Table 25)

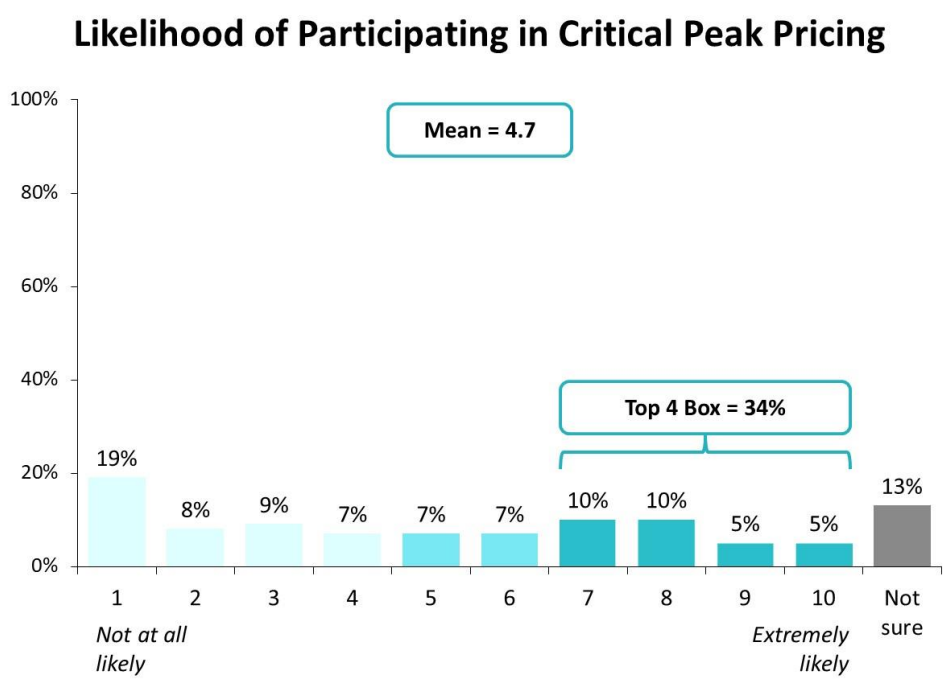
Option B: *Critical Peak Pricing*

On winter weekdays when the electrical grid is at peak capacity, Nova Scotia Power may announce a "Critical Peak Event." There would be up to a maximum of twenty-two, 4-hour events called where prices would be higher during these peak period hours to reflect the higher cost of providing energy during that period. These peak period hours would only occur during the months of November to March. In exchange, the price for energy the remainder of the year would be less than the current standard rate. Customers on this plan would be notified by text message and/or email the day prior (4PM) and before the critical peak event occurs, providing them the ability to adjust their electricity consumption to manage costs.

For this plan, the cost of electricity during the peak hours would be $1.50/kWh for 72 hours of the year and would be $0.13/kWh during lower cost hours.

For comparison, the current standard rate for electricity that most residential customers pay is $0.16/kWh.

Peak hours when electricity costs are higher would be specific to the day. Those who use this pricing plan would receive a text message or email the day before to let them know when the peak hours will be.



Q.25: Based on this description, how likely would you be to participate in this type of plan? (n=7,675) *Note: Responses of 'Not sure' are excluded from all summary statistics.*

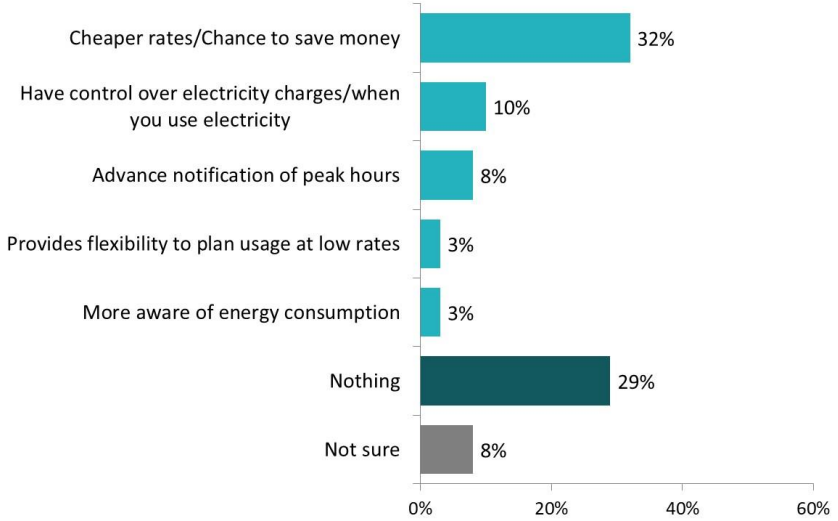
Likes and Dislikes of Critical Peak Pricing

Unaided, customers most like the chance to save money on their electricity bill, while most dislike the perception that peak rates are too high.

Most commonly, one-third of customers note liking the ***cheaper rates and chance to save money***. That said, three in ten indicate they ***do not like anything about the concept***. This is compared to 15 percent who said the same about the Time of Use concept. When asked what customers dislike about the concept, ***rates being too high*** are most commonly mentioned by one-third.

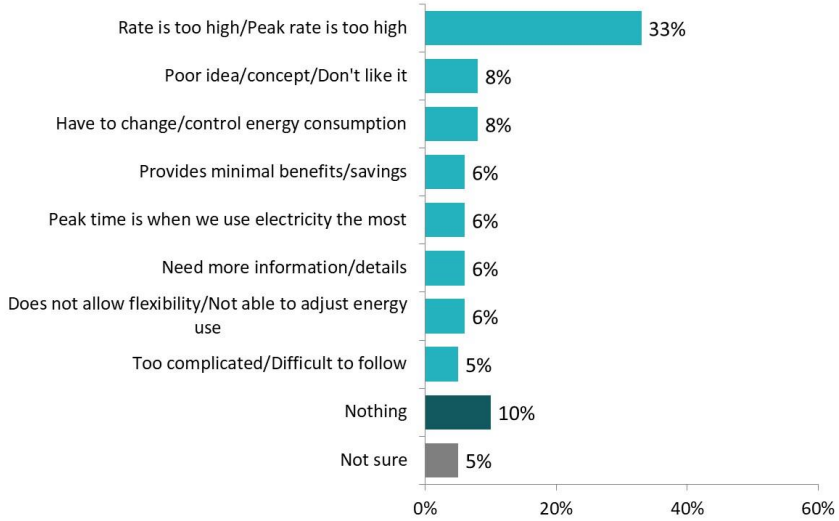
Of note, results displayed on this page reflect verbatim comments of customers shared in an open-ended question that were then coded into categories.

Like About Critical Peak Pricing Concept
Key Unaided Mentions



Q.25a: What do you **like** about this concept? (n=500) *Note: 500 responses were chosen at random for coding for this question.*

Dislike About Critical Peak Pricing Concept
Key Unaided Mentions

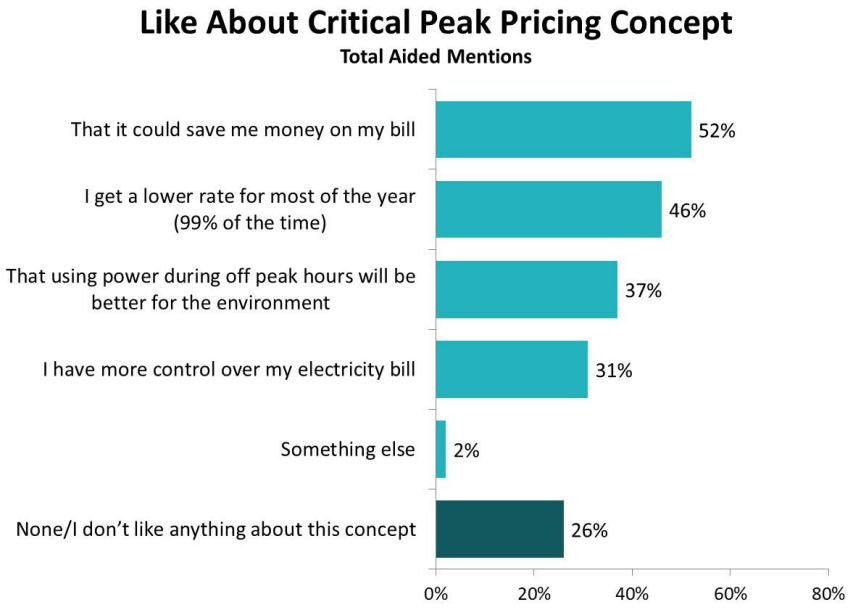


Q.25b: What do you **dislike** about this concept? (n=500) *Note: 500 responses were chosen at random for coding for this question.*

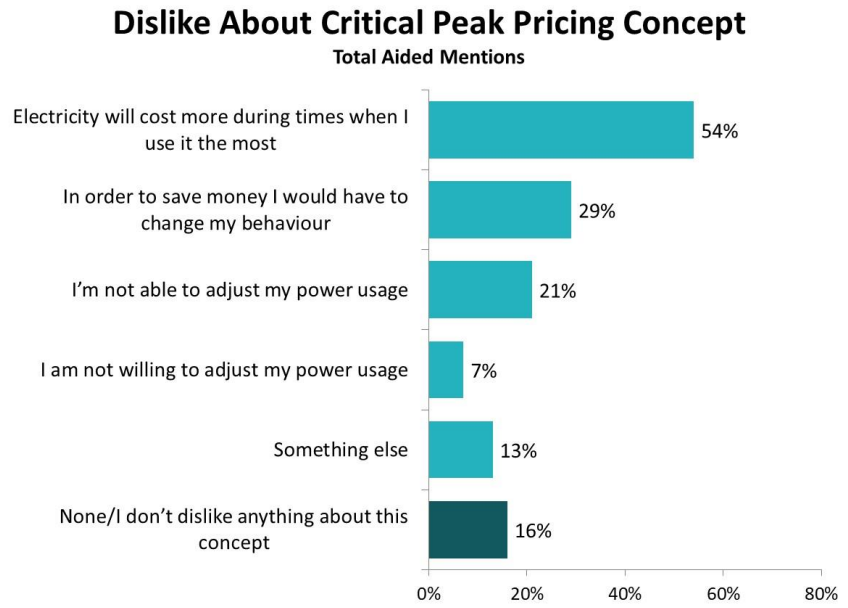
Likes and Dislikes of Critical Peak Pricing (Continued)

Customers were once again asked what they liked and disliked about the Critical Peak Pricing concept, this time prompted with options to choose from.

Most commonly, customers like ***that they could save money on their bill***, as selected by one-half, while just under one-half like ***that they get a lower rate for most of the year*** and approximately one-third each like that ***using power during off peak hours will be better for the environment*** and ***they will have more control over their electricity bill.*** Meanwhile, more than one-half of customers dislike that ***electricity will cost more during times when they need it most,*** and three in ten dislike that ***in order to save money they would need to change their behaviour.*** Two in ten customers also note that they are ***not able to adjust their power usage,*** while only seven percent indicate they are ***not willing to.*** (Tables 25c and d)



Q.25c: And from the list below, what do you **like** about the concept? (n=7,675)



Q.25d: And from the list below, what do you **dislike** about the concept? (n=7,675)

NARRATIVE RESEARCH

Preferred Rate Plan

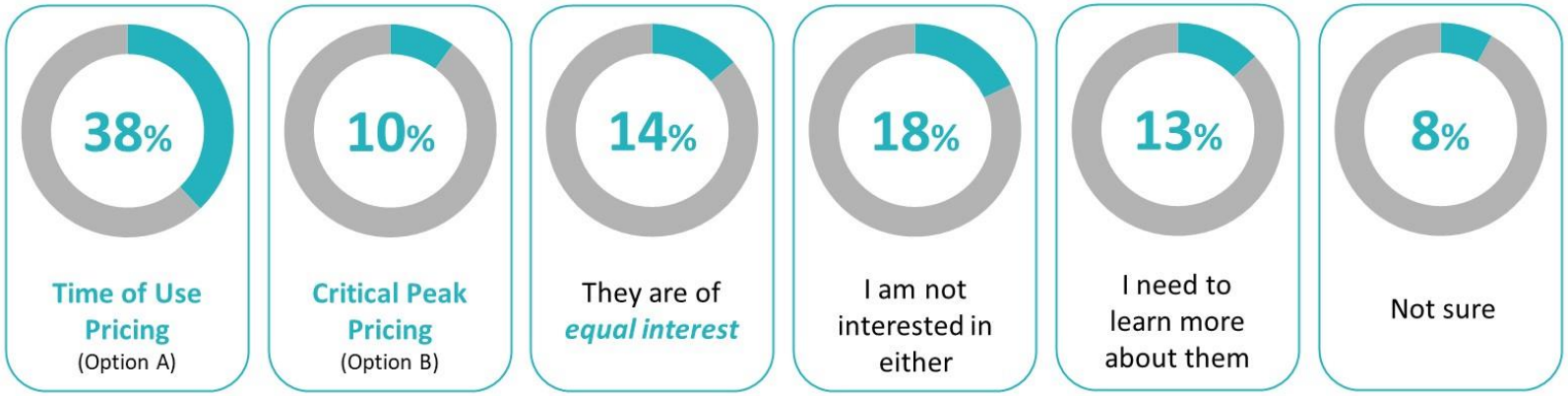
Preferred Rate Plan

Between the two rate plans proposed, customers express much greater interest in the Time of Use plan overall.

More specifically, four in ten customers select the ***Time of Use plan*** as being most of interest to them, while only one in ten select the ***Critical Peak Pricing Plan***. Meanwhile, just over one in ten indicate ***they are of equal interest***, while two in ten ***are not interested in either plan***. Additionally, just over one in ten would ***need to learn more about the plans***, and one in ten are ***unsure***.

Across customer demographics, interest in the Time of Use plan increases with household income, and is higher among e-billing customers. Meanwhile, interest is consistent for Critical Peak Pricing. Interest in the proposed Time of Use plan is also elevated among customers who are more familiar with the existing Time of Use plan, perhaps suggesting that greater familiarity with the concepts could increase interest.

Concept Most Interested In



Q.26: Of the two concepts being considered, which is of greater interest to you? (n=7,675)

Reasons for Greater Interest in Time of Use

Of those most interested in Time of Use, the main reason is because it is easier to implement into their schedule.

Most commonly, three in ten indicate their preference for the Time of Use plan because it ***is easier to implement into their schedule***, while approximately one in six each mention ***more control over their consumption, price,*** and ***better savings.***

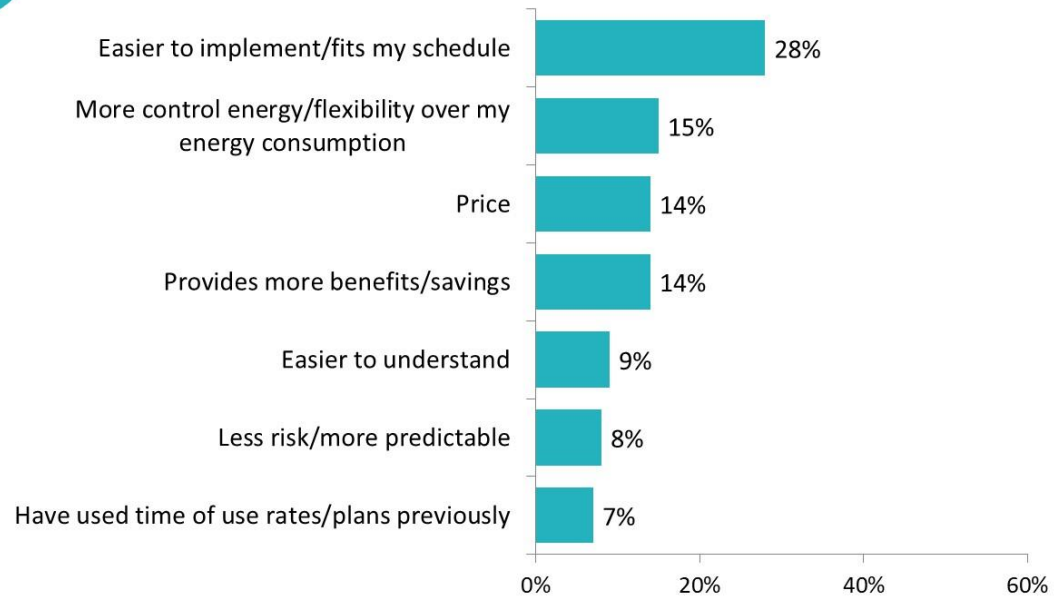
Across customer demographics, customers who use oil heat as their primary source, as opposed to customers who use electricity primarily, are more likely to mention that this plan ***gives more control over their consumption***.

Caution should be taken when interpreting some customer demographic subgroups given small sample sizes. (Table 26a – Time of Use)

38% ***Are more interested in Time of Use Pricing***

Reasons for Greater Interest in Time of Use Pricing

Key Unaided Mentions
Among Those Who Are More Interested in Option A – Time of Use Pricing



Q.26a: **[IF INTERESTED IN OPTION A – TIME OF USE PRICING IN Q.26]** Why are you more interested in Option A – Time of Use Pricing? Please be as specific as possible. (n=500) *Note: 500 responses were chosen at random for coding for this question.*

Reasons for Greater Interest in Critical Peak Pricing

Of those most interested in Critical Peak Pricing, the main reason is for the potential cost savings.

Most commonly, one-third indicate their preference for the Critical Peak Pricing plan because of its ***potential cost savings and lower rates throughout the year***. Meanwhile, approximately two in ten each mention that peak events are ***only during certain months***, and it ***provides more control over their usage.*** Just over one in ten each also mention that it ***better suits their lifestyle,*** and because ***they are notified in advance***.

Across customer demographics, younger residents are most likely to mention preferring the program because of the ***potential cost savings*** and because ***it is only certain months***.

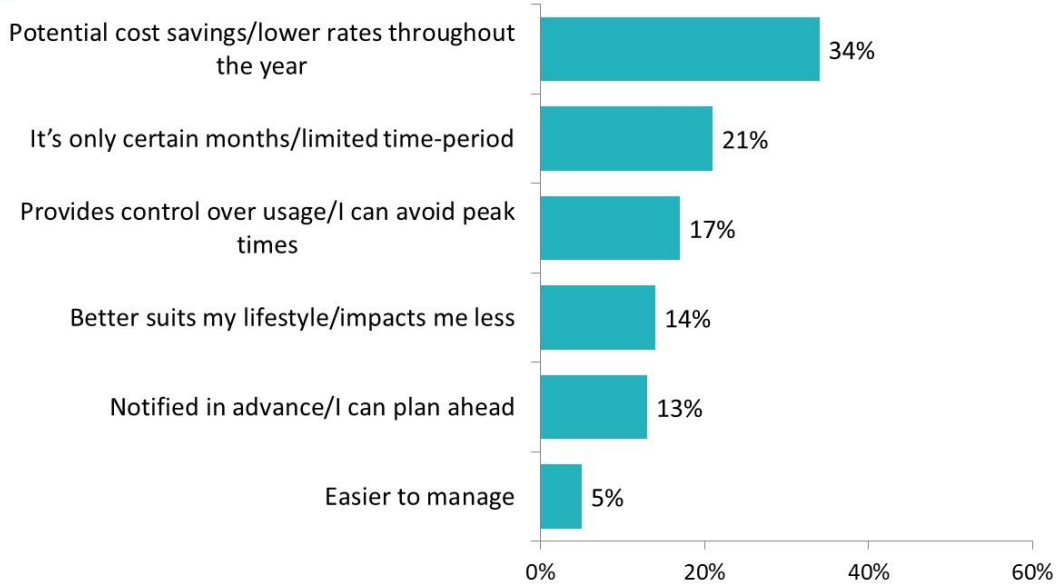
Caution should be taken when interpreting some customer demographic subgroups given small sample sizes. (Table 26a – Critical Peak Pricing)

10% ***Are more interested in Critical Peak Pricing***

Reasons for Greater Interest in Critical Peak Pricing

Key Unaided Mentions

Among Those Who Are More Interested in Option B – Critical Peak Pricing



Q.26a: **[IF INTERESTED IN OPTION B – CRITICAL PEAK PRICING IN Q.26]** Why are you more interested in Option B – Critical Peak Pricing? Please be as specific as possible. (n=500) *Note: 500 responses were chosen at random for coding for this question.*

Reasons for Disinterest in Either Plan

Customers not interested in either program provide a variety of reasons as to why, with minimal savings being most common.

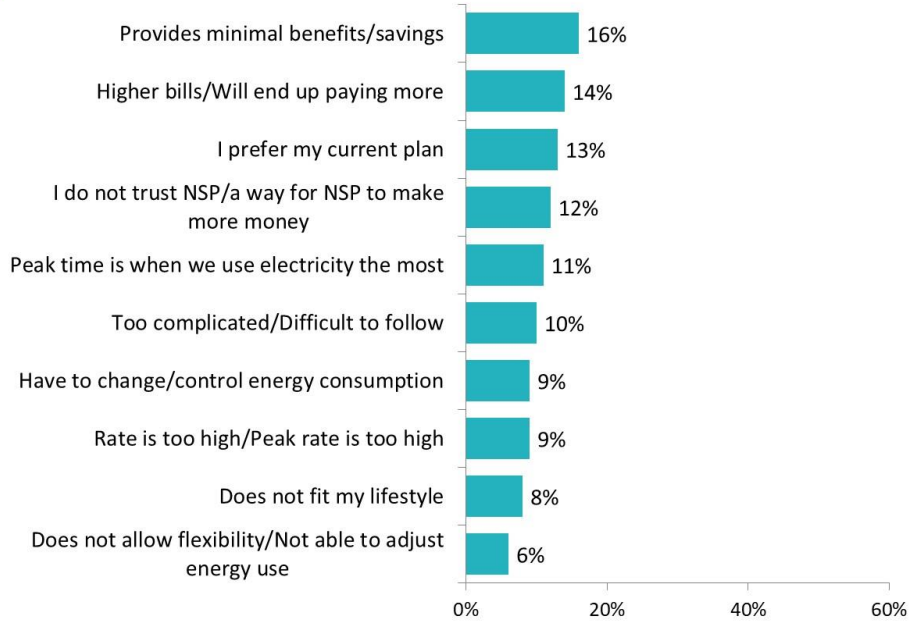
Most commonly, customers express being not interested in either pricing plan because ***it provides minimal benefits*** (16%), ***bills will be higher*** (14%), ***they prefer their current plan*** (13%), they ***don't trust NSP*** (12%), ***peak times are when they use the most electricity*** (11%), and ***it is too complicated*** (10%), among others.

Caution should be taken when interpreting some customer demographic subgroups given small sample sizes. (Table 26b)

18% *Are not interested in either pricing plan*

Reasons for Not Being Interested in Either Pricing Plan

Key Unaided Mentions
Among Those Who Are Not Interested in Either Pricing Plan



Q.26b: **[IF NOT INTERESTED IN EITHER OPTION IN Q.26]** Why are you not interested in either pricing plan? Please be as specific as possible. (n=500) *Note: 500 responses were chosen at random for coding for this question.*

Interest in Learning More

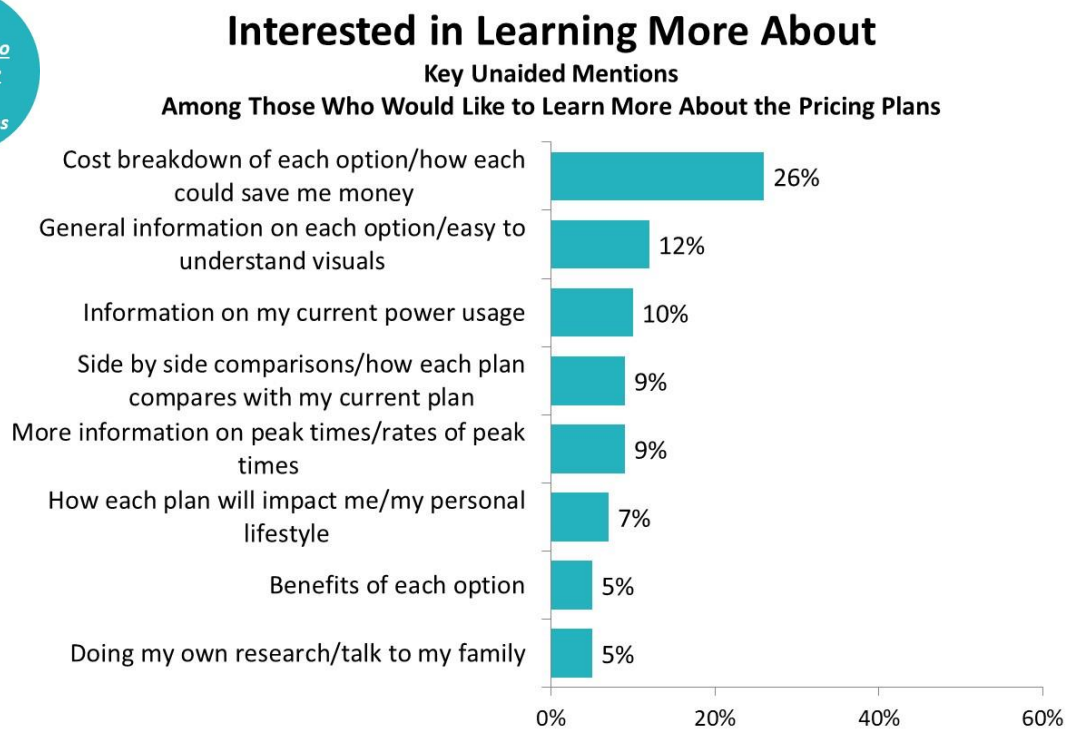
Customers who express being interested in learning more before choosing between the two plans would most commonly like to see a cost breakdown of each option and better understand how each could save them money.

One-quarter of customers interested in learning more about the pricing programs indicate that ***seeing a cost breakdown of each option*** would help them make a decision. This aligns with Nova Scotia Power's plan of providing customers with a savings calculator to help them choose which plan is right for them.

Meanwhile, customers also mention wanting to learn more ***general information on each option including some easy to understand visuals***, and ***information on their current power usage***, among other topics.

Results are largely consistent across customer demographics, though caution should be taken when interpreting some customer demographic subgroups given small sample sizes. (Table 26c)

13% *Would like to learn more about the pricing plans*



Q.26c: **[IF WOULD LIKE TO LEARN MORE ABOUT THEM IN Q.26]** What specifically are you interested in learning more about? Please be as specific as possible. (n=500) *Note: 500 responses were chosen at random for coding for this question.*

Required Savings

On average, customers are looking to save more than $300 per year to make the programs worthwhile to them, though a majority would take part in order to save less than $300.

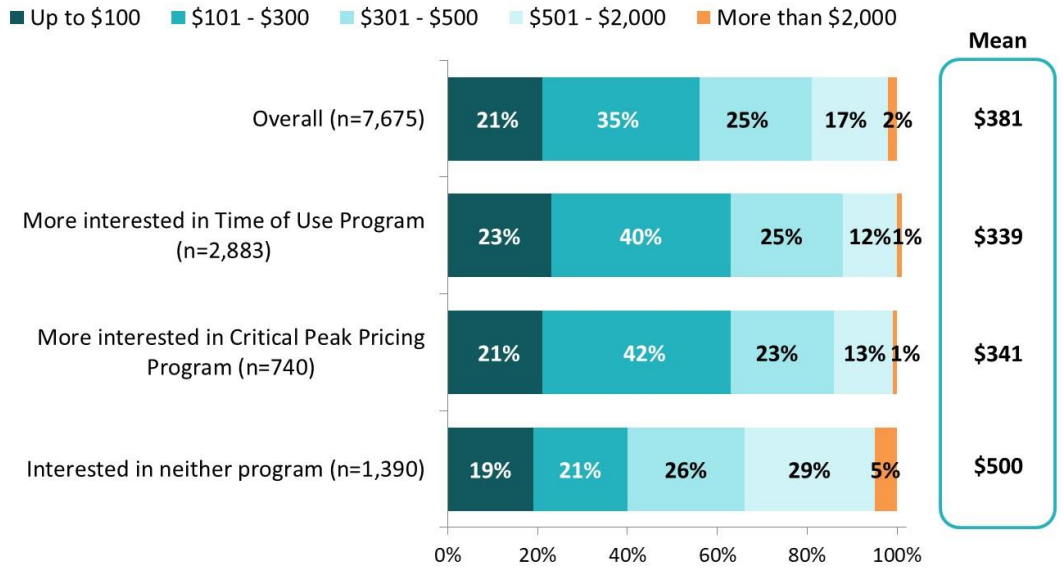
Regardless of a customer's interest in the programs, each was asked how much they would need to save on their power bills each year to make the program worthwhile for them. Overall, customers are expecting a great deal of savings with the average being ***$381*** per year.

When looking at the two programs individually, results are highly consistent with customers more interested in the Time of Use plan wanting to save an average of ***$339***, and customers more interested in Critical Peak Pricing wanting to save an average of ***$341***. Not surprisingly, customers not interested in either plan would want to see greater savings to make the program worthwhile for them, providing an average annual savings of ***$500***.

It is important to note that a majority overall, specifically two thirds of those interested in either program would need to save *less than $300 a year* in order for the program to be worthwhile, and two in ten would be happy to save up to $100.

Across customer demographics, required savings are highest among customers with electric heat, customers with a heat pump, and households with more people. This is perhaps understandable, as these customers can be assumed to have larger power bills than their counterparts. (Table 26d)

Savings Needed on Bill Each Year to Make Program Worthwhile



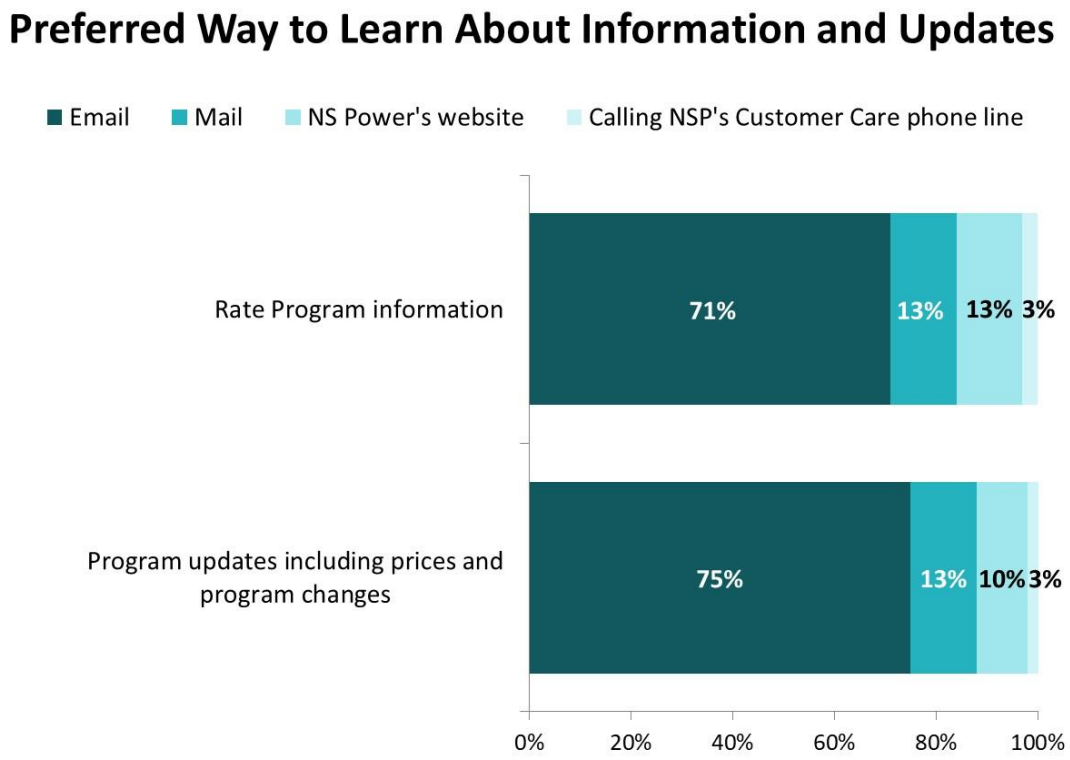
Q.26d: How much would you need to save on your bill each year to make the program worthwhile for you? (n=7,675) *Note: Responses greater than $2,000 were excluded from the calculation of the mean.*

Preferred Means of Learning More

When learning about rate program information and program updates, email is by far the most preferred method of communication.

For both ***rate program information*** and ***program updates including prices and program changes***, the majority of customers would prefer to receive these updates through ***email***. Meanwhile, approximately one in ten each would like to receive them ***by mail*** and the ***Nova Scotia Power*** website. Only three percent of customers would like to receive these updates by ***calling NSP's Customer Care phone line***.

Not surprisingly, ***email*** is preferred by e-billing customers, while paper bill customers would prefer to receive these updates by ***mail***. Otherwise, preferred communication methods are consistent across customer demographics.



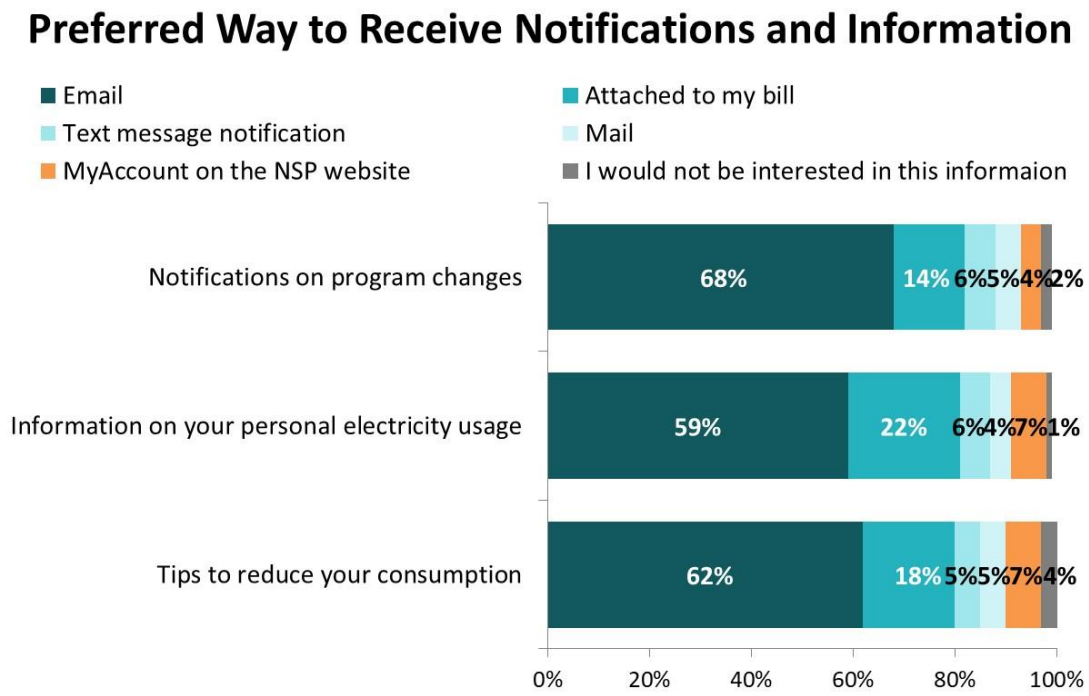
Q27a-b: What would be your preferred way to learn more about each of the following? (n=7,675)

Preferred Means of Receiving Notifications

When participating in a program, program updates would be most preferred by email.

Similar to more general program updates, customers were asked how they would like to receive ***notifications on program changes, information on personal electricity usage***, and ***tips to reduce consumption***, if they were participating in one of these proposed programs. For each type of update, the majority would prefer to receive it by ***email***, while a small proportion would also be interested in receiving a notice ***attached to their bill***. Comparatively few would prefer to receive notifications via ***text message***, ***Mail***, or ***MyAccount.***

Perhaps not surprising, e-bill customers are much more likely to prefer receiving each of these notifications through ***email***, while paper bill customers are much more likely to prefer updates ***attached to their bill***. (Table 28a-c)



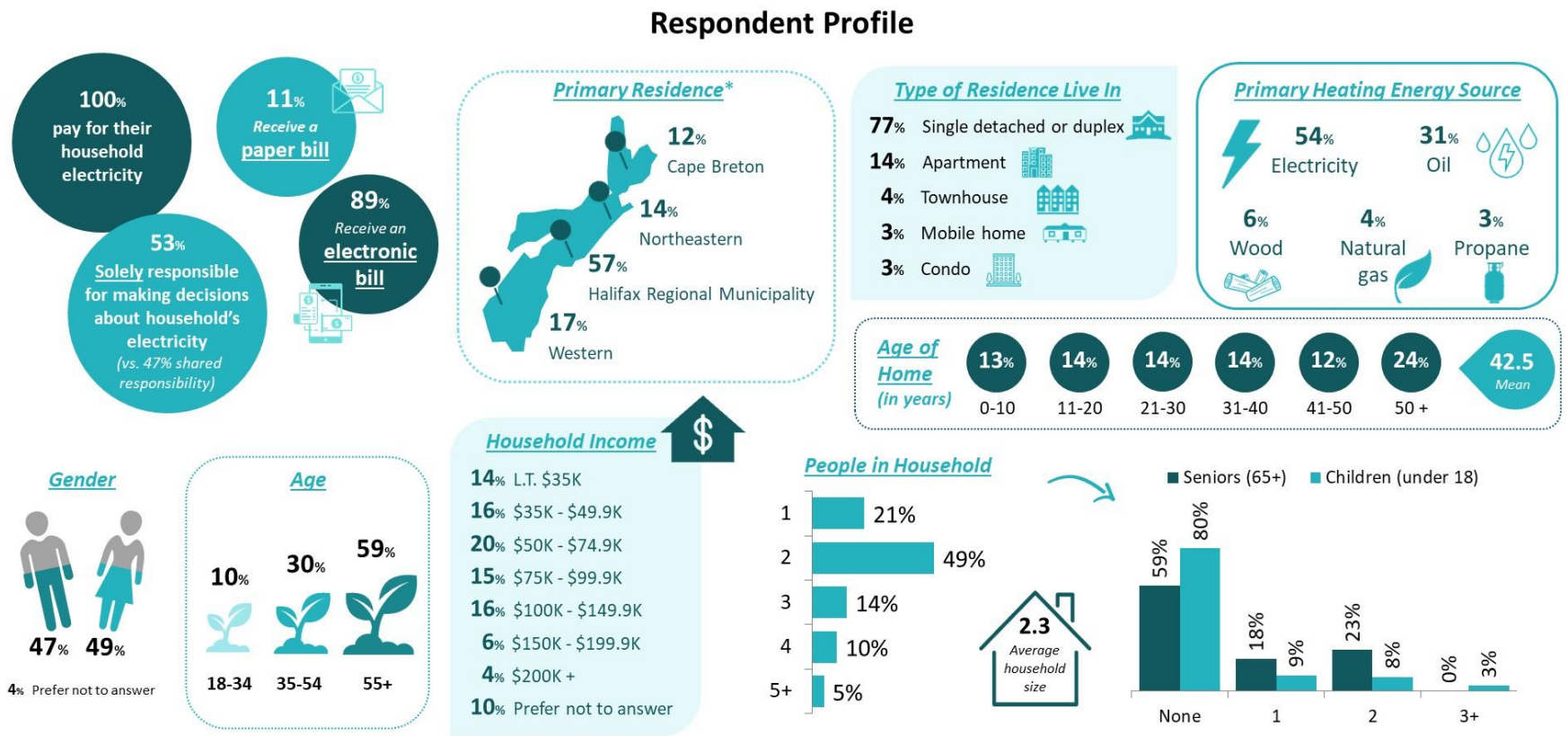
Q28a-c: If you were participating in one of these programs, Nova Scotia Power would also have the ability to send notifications and share customized information on your electricity usage (e.g., to let you know which appliances are using the most electricity and tips on how to lower your power bill). For each of the items below, please select your most preferred way to receive it? (n=7,675)

NARRATIVE RESEARCH

Respondent Profile

Respondent Profile

The following provides a brief profile of the customers that participated in the survey.



Overall: (n=7,675) | **Note: Not all postal codes provided by panel members could be alinged with the four regions. (n=7,663)*



Every insight tells a story.


Nova Scotia
POWER
An Emera Company
TVP Tariff Pilot – Technical Session 1
March 3, 2025
Revised/redistributed: 13 March 2025
1

Summary of Updates/Revisions

(13 March 2025 Redistribution)

- Slide 7 – added a close parenthesis after Environics.
- Slide 28 – changed "(provided on the next two slides)" to "(provided on the next slide)"
- Slide 37 – Summary of Residential Recruitment Key Contacts:
  - Under Highlights - move point on email to the first to flow better with the order of the table metrics
  - Updated Year 4 Click Rate (now 19%) and YOY (now -9%)
  - Updated Year 4 Results, see table below:

	Year 4 Results (previously shared)	Year 4 Results (updated)
Enrolment Target	*7,000 TOU / 3,500 CPP*	7,000 TOU / 3,500 CPP
Applications Received	*4,703 TOU / 2,487 CPP*	4,097 TOU / 2,487 CPP
Pilot Enrolment	*4,137 TOU / 1,973,756 CPP*	5,977 TOU / 2,756 CPP
% of Target Achieved	*85.7% TOU / 79% CPP*	85% TOU / 79% CPP

- Slide 38 – Summary of Business Recruitment Key Contacts:
  - Added footnote on CPP applications * Please note: In some cases, one (1) application may have been submitted for multiple SMB accounts
  - Updated Year 4 Results, see table below:

	Year 4 Results (previously shared)	Year 4 Results (updated)
Enrolment Target	*500 TOU / 500 CPP*	1,000 TOU / 1,000 CPP
Applications Received	*0 TOU / 26 CPP*	0 TOU / 26 CPP *
Pilot Enrolment	*54 TOU / 53 CPP*	54 TOU / 53 CPP
% of Target Achieved	*11% TOU / 11% CPP*	5% TOU / 5% CPP

- Slide 39 – Residential Recruitment
  - Updated table with numbers, fixed error and updated now with the most recent data (as of March 4, 2025), see table below:

(previously shared table)	*TOU (Rate 80, 81)*	*CPP (Rate 70, 71)*	*Residential Total*
Enrollment Target	*7,000*	*3,500*	*10,500*
Year 4 New Applications	*4,703*	*2,487*	*7,416*
Year 4 Accepted New Applications	*4,137*	*1,973*	*6,136*
Current Enrollment (As of January 9, 2025)	*5,999*	*2,764*	*8,763*

- Slide 40 – SMB Recruitment
  - Updated SMB enrollment target numbers and percentage target achieved.
  - Confirmed current enrollment numbers as of March 4 however enrollment numbers remained the same, see table below:

(previously shared table)	*TOU (Rate 80, 81)*	*CPP (Rate 70, 71)*	*Commercial Total*
Enrollment Target	*500*	*500*	*1,000*
Year 4 New Applications	*0*	*26*	*26*
Current Enrollment (As of January 9, 2025)	*54*	*53*	*107*

- Slide 43 – updated number of customers signed up on mailing list from 560 to 650

Agenda

1. Welcome & Introduction
2. Review Work Plan for Today's Session
3. Accessibility of TVP
4. Review of Current Tariffs, Mechanisms & Capabilities
5. Marketing Update
6. Technical Session 2 Work Plan & Near Term Next Steps

Ongoing Pricing Innovation Process

1. **Analytics-based:** using 15-minute cloud scale analytics data to model
   - **Tariff Optimization Model**
   - **Rate Design Scorecard**

2. **Collaboration-focused:** collaboration with Regulatory Intervenors and Customers
   - **Stakeholder Engagement** sessions with both Regulatory TVP group and MURB Customers
   - Incorporating customer feedback from surveys
   - **Phased approach**: (i.e. engage, pilot, EM&V, refine, production)

3. **Strategically aligned:** with Resource Planning & the Path to 2030 – e.g. IRP, Load Forecast

2024/25 Areas of Focus Work Plan

For Discussion Today (Technical Session 1 of 3)

Summary of 2024/25 Areas of Focus & Board Directives	Type	Items to be Discussed/Reviewed
1.0 – Accessibility of TVP • (1.1) Review of accessibility as applicable to vulnerable customers (i.e. low-income)	CA	• Examine the results of the Year 3 report as it relates to income and develop proposal to address gaps/opportunities , as appropriate • Assess potential impacts to vulnerable customers • Examination of challenges with more detailed income analyses (e.g. lack of control group) • **NEW** – in response to the Consumer Advocate's comments, NS Power will provide a summary of applicant characteristics (e.g. customer home type, primary heating source) for review and discussion re. barriers to accessing TVP Tariffs for renters v. homeowners
2.0 – Review of Current Tariffs, Mechanisms & Capabilities • (2.1) exploration of TVP revenue stability mechanisms	CA	• **NEW** – TVP revenue stability will be explored using the structural and load shift revenue neutrality models and/or avoided cost models. • **REVISED** – Any MURB rate adjustments or refinements will be proposed to the stakeholder's group once sufficient data is available and analysis has been completed. • Continuous refinements are made annually on the TVP load reduction methodology. NS Power understands that the TVP results by space heating classification did not provide tangible results, this methodology will be reviewed by NS Power in consultation with Econoler; findings will be presented. Comments / direction on this matter from stakeholders are welcome. • Provide update on status of current metering and CIS system capabilities and future potential capabilities with system upgrade and plan to address in TVP strategy. • Provide an assessment of revenue impacts and potential tools available to address as required (e.g. enrolment targets, rate design scorecard) • Review of marketing and communication efforts for 2024/25 recruitment
• (2.2) MURB TOU Pilot Tariff should continue to be refined to better reflect the value of load shifting by considering marginal costs (or avoided costs) in determining the rates in each period	BD	
• (2.3) work with stakeholders to refine its methods of estimating load reductions achieved through the TVP tariffs	BD	
• (2.4) review of current metering and billing (Customer Information System) system capabilities	CA	



1.0 – Accessibility of TVP

EM&V Income-Related Findings from Year 3 Report

Source of Income Data:

- Existing income data is based on average income at the postal code level (sourced from Environics). As a result, income data is only indicative in broad metrics, and results from more granular analysis may not result in a meaningful conclusion.
- Self-reported income is collected from those who voluntarily disclose it, with no verification as part of the application process. Self-reported income data from enrolment is not able to be used in this analysis as Nova Scotia Power does not collect income level data of all customers, which would provide a control group for which the TVP enrolment/survey income level data could be evaluated

Figure 2: Average Morning Load Reduction – TOU Participant Segmentation

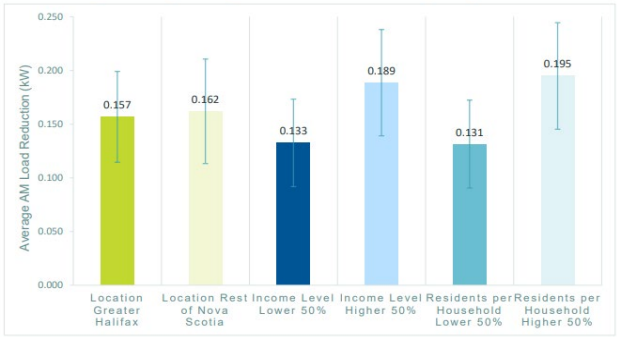
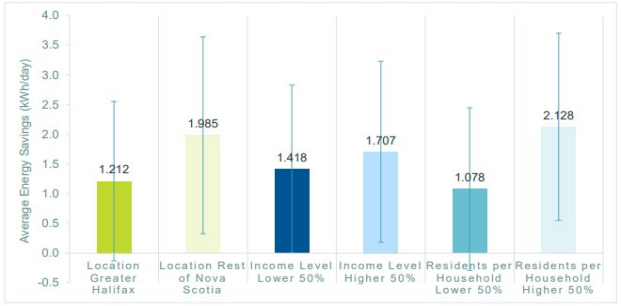
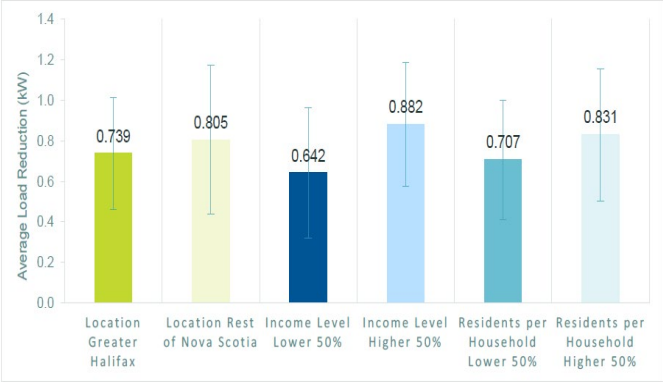


Figure 4: Winter Usage Level Impacts by Participant Segment (TOU)



EM&V Income-Related Findings from Year 3 Report

Figure 7: Average Morning Event Load Reduction – CPP Participant Segmentation



Does income pose a barrier to meaningful participation and savings?

- The variance in Peak Load Reduction being less than the whisker error bars indicates that there is no evidence of income being a barrier to absolute savings. Even if the results were statistically significant, the savings, although lower on an absolute level, do not appear to show a barrier to meaningful participation or savings based on income.
- The Narrative Research survey of existing participants indicates a high level of satisfaction across income levels. Although the survey does show a small dip in satisfaction in the lowest income bracket, that bracket suffers from a low sample size as highlighted by Narrative. Despite this the income bracket in question still shows a high level of satisfaction. This adds to the conclusion that income is not a barrier currently.

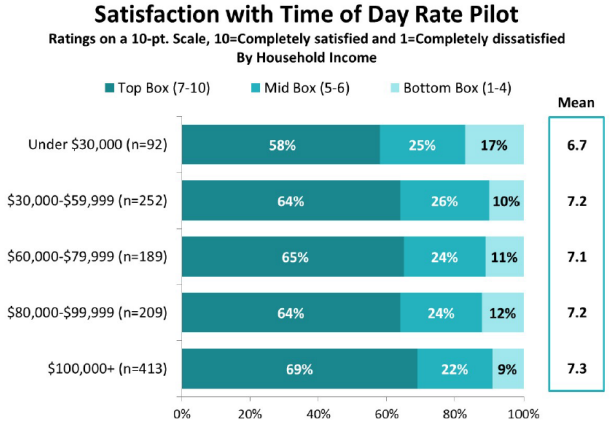
EM&V Income-Related Findings from Year 3 Report

Moving forward

- NS Power remains open to additional segmenting of income in future reports with these limitations in mind if there are additional questions it can answer that may help improve the effectiveness of the TVP program.
- The nature of any additional questions will determine the approach in segmenting the data to yield the most meaningful result within the confines of available data. At this time, NS Power believes the existing methodology has satisfactorily answered the question that was asked of it.

Satisfaction with Time-of-Day Pilot – Household Income

Low-income households are slightly less likely to provide top box satisfaction scores, but small sample size should be noted.

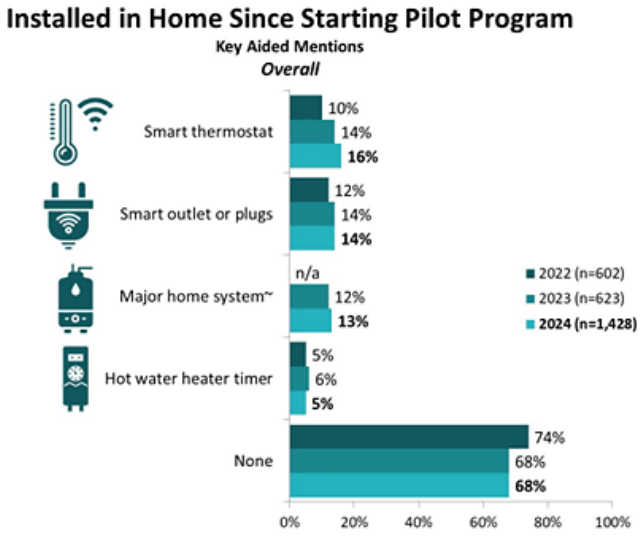


Q.24b: What is your overall satisfaction with the Time of Day Rate Pilot? *New question in 2024.*

Other Income-Related Learnings

- Through Nova Scotia Power's work with our customers and the NSP/CA/AEC Low-Income Working Group, the following learnings on rate design as it relates to income should be considered where possible in future TVP changes and offerings.
  - An expanded enrolment window would be welcome where customers would not have to sign up prior to the heating season which is already challenging for customers.
  - Offering customers choice in rates and not defaulting anyone to a rate that may not be appropriate for them.
  - They are supportive of the work we are doing to, and assistance provided to customers in advising the appropriate a rate for the customer would like to see this further developed.
  - Although appreciative of annual savings, savings in every month is also valued when deciding on enrolling in a rate

Accessibility of TVP Tariffs for Renters



- TVP tariffs have been designed to provide customers with choice and flexibility – there are no restrictions for renters to join a TVP Tariff
- Current TVP Tariffs are also designed to be technology agnostic (which may be especially beneficial for renters)
- Customer survey results from Year Three of the Program (shown left) show the majority of customers on the pilot (68%) have not installed new equipment since enrolling on the rates
- In the Year 4 enrolment cohort, 895 (12.6%) of applications were customers identifying as living in an apartment
  - This represents an increase of approximately 84% over the number of applications in the Year 3 enrolment cohort (n = 147 or 6% of total applications)

Summary of Year Four Applicant Characteristics

Applicant Income	
< $19,999	4.1%
$20,000 to $29,000	6.2%
$30,000 to $39,999	7.2%
$40,000 to $49,999	8.5%
$50,000 to $59,999	8.7%
$60,000 to $74,999	12.5%
$75,000 to $99,999	13.6%
$100,000 to $149,999	11.5%
$150,000 or more	6.4%
Prefer not to say	13.2%
(blank)	8.1%

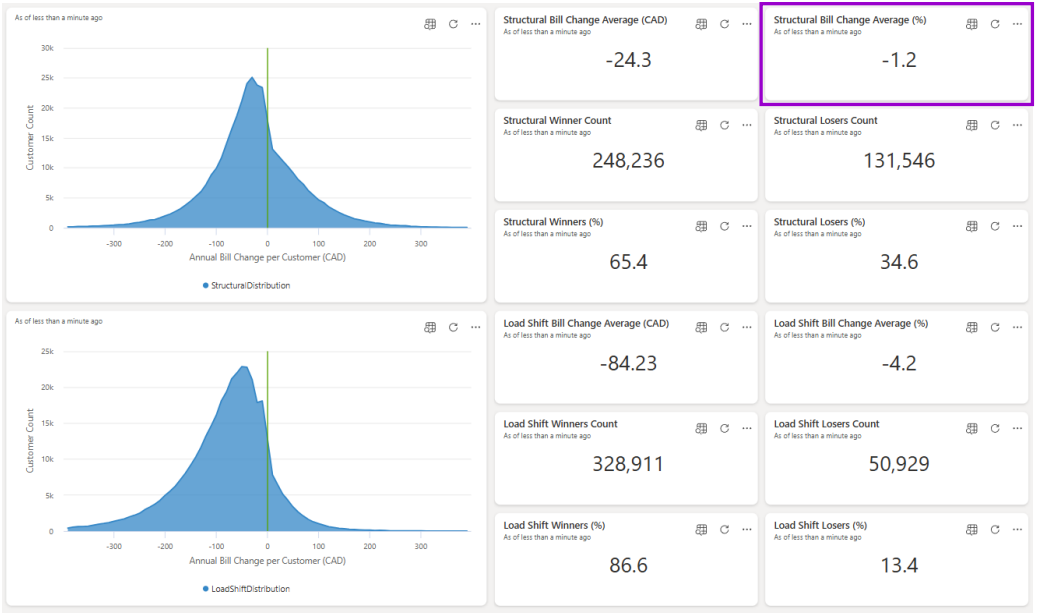
Applicant Primary Heating	
Heat Pump	42.6%
Electric baseboards	22.9%
Oil	18.3%
(blank)	4.4%
Included in rent/condo fee	3.9%
Wood	3.4%
Propane	2.1%
Natural Gas	2.0%
Other	0.5%

Applicant Residence	
Single Family/Detached	65.4%
Apartment	12.6%
Duplex	7.3%
(blank)	5.0%
Mobile home	3.7%
Townhouse	3.6%
Condo	2.3%



2.0 – Review of Current Tariffs, Mechanisms & Capabilities

Domestic, TOU



Model Commentary

TOU volumetric rates effective November 1, 2024

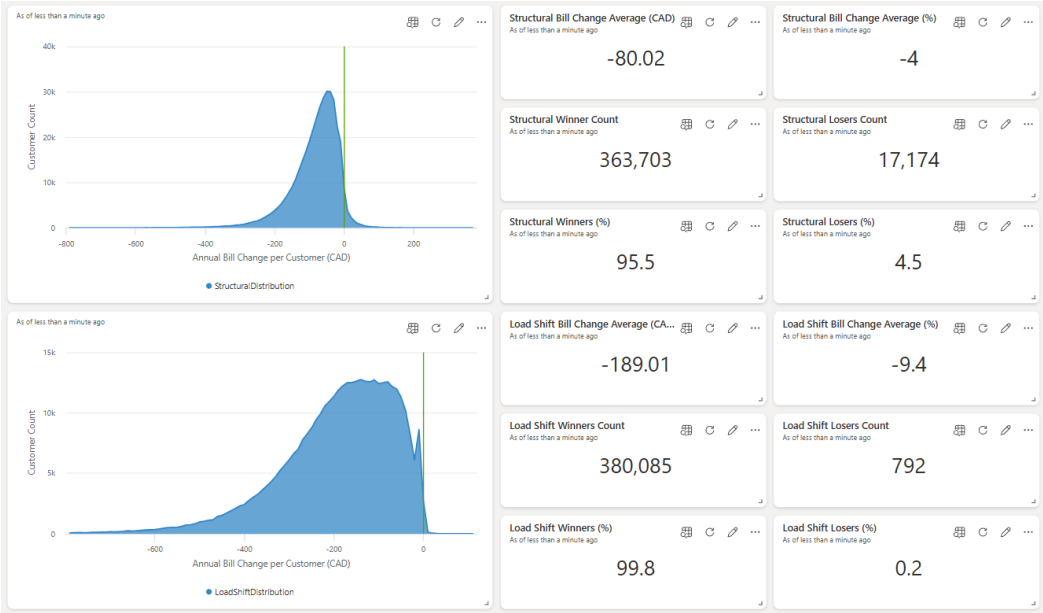
Includes 2025 riders

AMI data domain: January 1 – December 31, 2024 inclusive

Structural bill change = -1.2 % note that technical sessions filed in 2024/2025 application reported a structural bill change of 0%[1]

[1] 20240731 NSPI to NSUARB Time-Varying Pricing 2024-2025 Application, Appendix C, Attachment 8, Page 14 of 39

Domestic, CPP (15 events)



Model Commentary

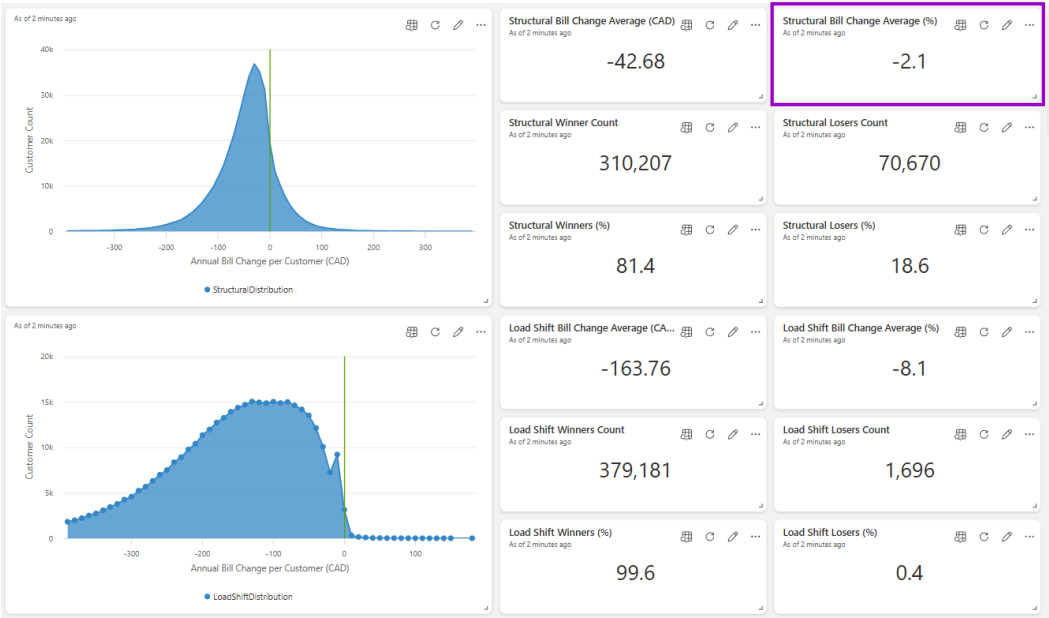
CPP volumetric rates effective November 1, 2024

Includes 2025 riders

AMI data domain: January 1 – December 31, 2024 inclusive

Presented for reference, not comparable to modeling submitted with the 2024/25 Application as only 15 events occurred in 2024.

Domestic, CPP (15 events, +3 hypothetical)



Model Commentary

CPP volumetric rates effective November 1, 2024

Includes 2025 riders

AMI data domain: January 1 – December 31, 2024 inclusive

3 additional events were added to the model to create a total of 18 events

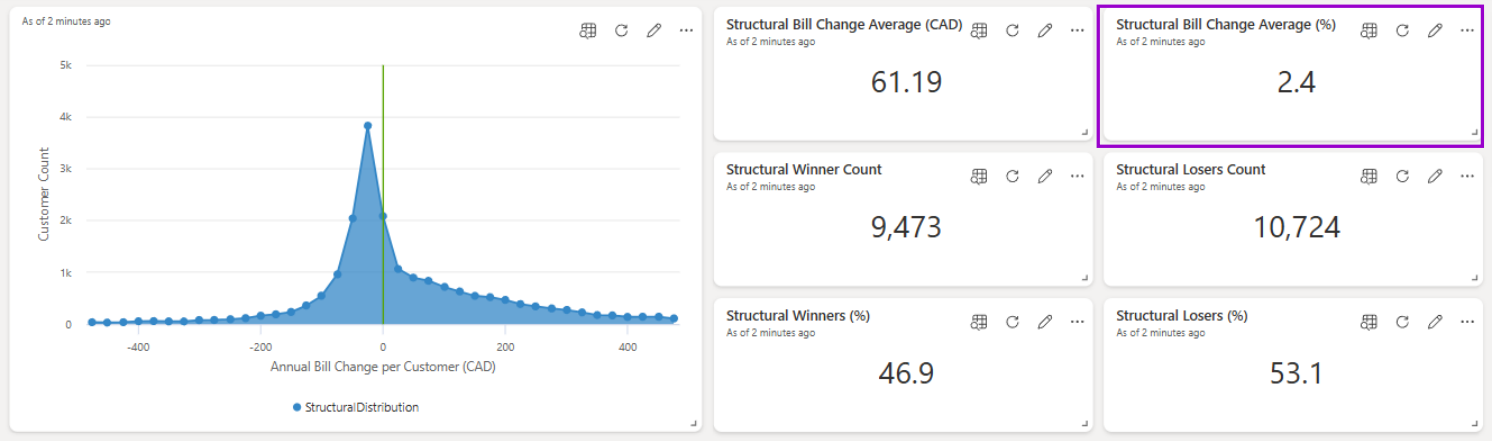
Structural bill change = -2.1 note that technical sessions filed in 2024/2025 application reported a structural bill change of -1.9%[1]

[1] 20240731 NSPI to NSUARB Time-Varying Pricing 2024-2025 Application, Appendix C, Attachment 8, Page 17 of 39

Small General, TOU

Model Commentary

- TOU volumetric rates effective November 1, 2024
- Includes 2025 riders
- AMI data domain: January 1 – December 31, 2024 inclusive
- Structural bill change = +2.4% note that technical sessions filed in 2024/2025 application reported a structural bill change of -2.6%[1]

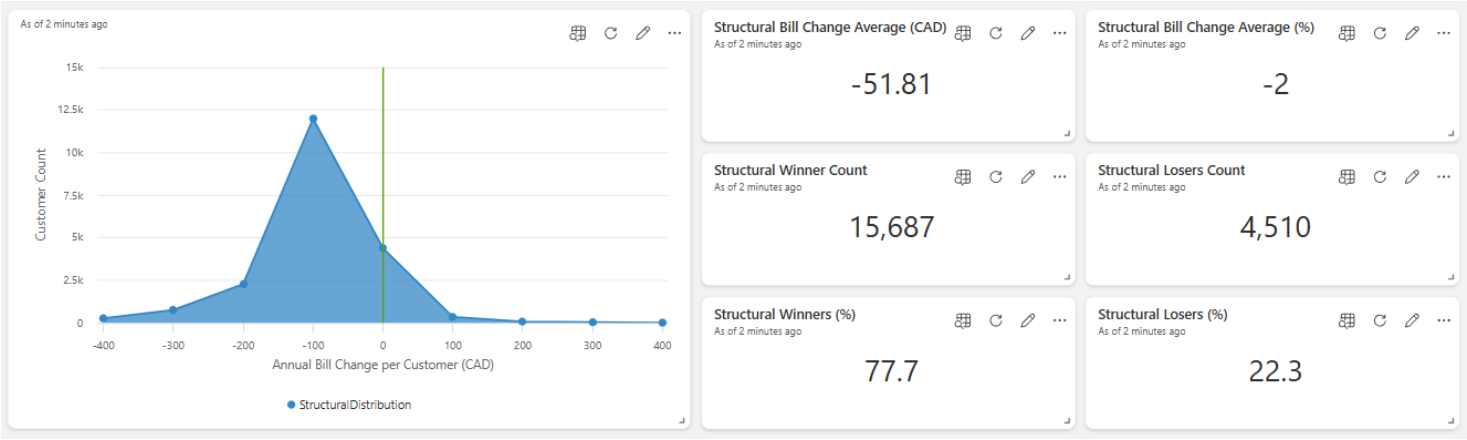


[1] 20240731 NSPI to NSUARB Time-Varying Pricing 2024-2025 Application, Appendix C, Attachment 6, Page 67 of 91

Small General, CPP (15 events)

Model Commentary

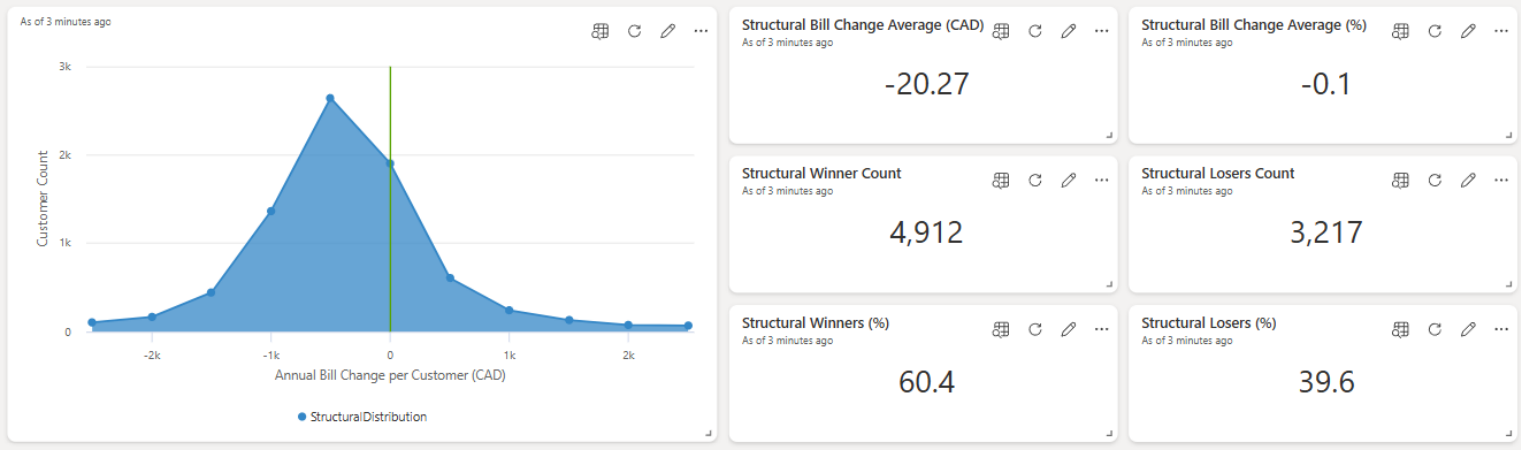
- CPP volumetric rates effective November 1, 2024
- Includes 2025 riders
- AMI data domain: January 1 – December 31, 2024 inclusive



General, TOU

Model Commentary

- TOU volumetric rates effective November 1, 2024
- Includes 2025 riders
- AMI data domain: January 1 – December 31, 2024 inclusive
- Structural bill change = -0.1% note that technical sessions filed in 2024/2025 application reported a structural bill change of -0.2%[1]

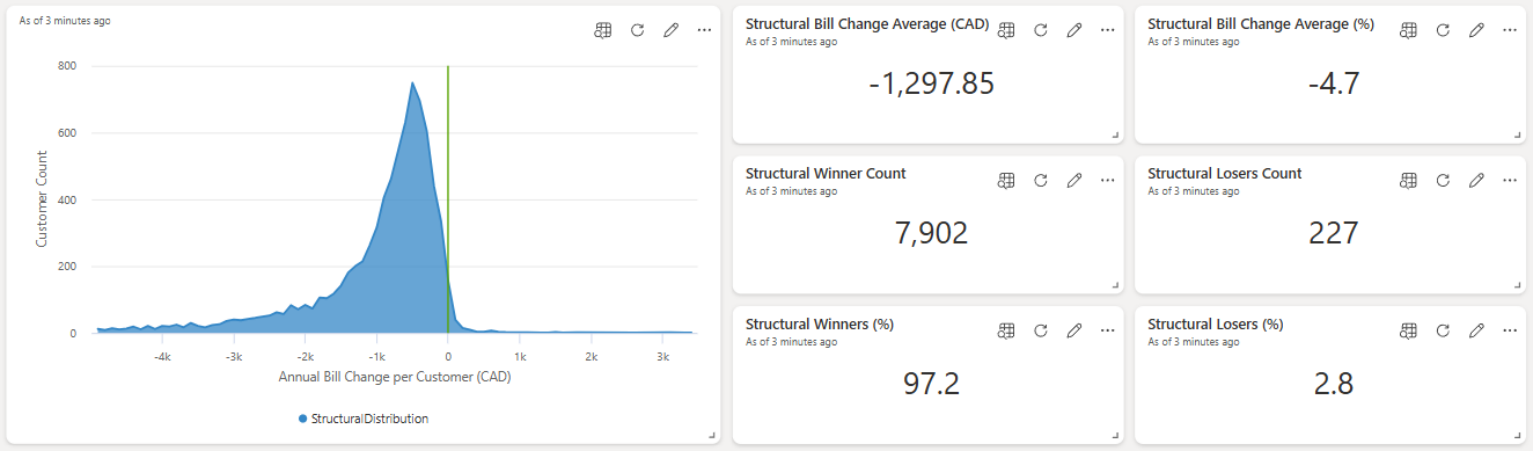


[1] 20240731 NSPI to NSUARB Time-Varying Pricing 2024-2025 Application, Appendix C, Attachment 6, Page 69 of 91

General, CPP (15 events)

Model Commentary

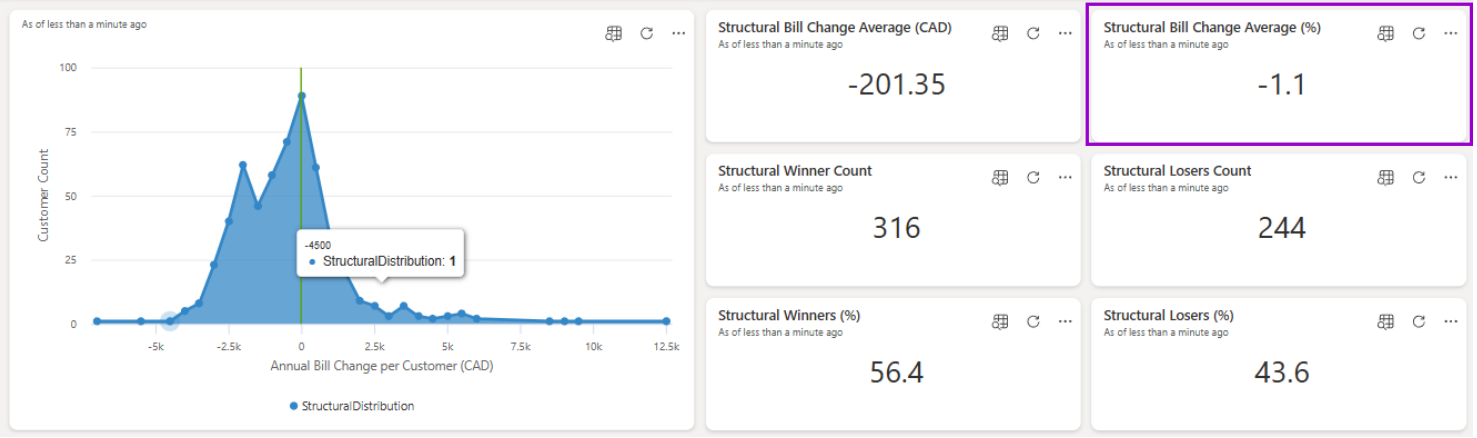
- CPP volumetric rates effective November 1, 2024
- Includes 2025 riders
- AMI data domain: January 1 – December 31, 2024 inclusive



MURB, TOU

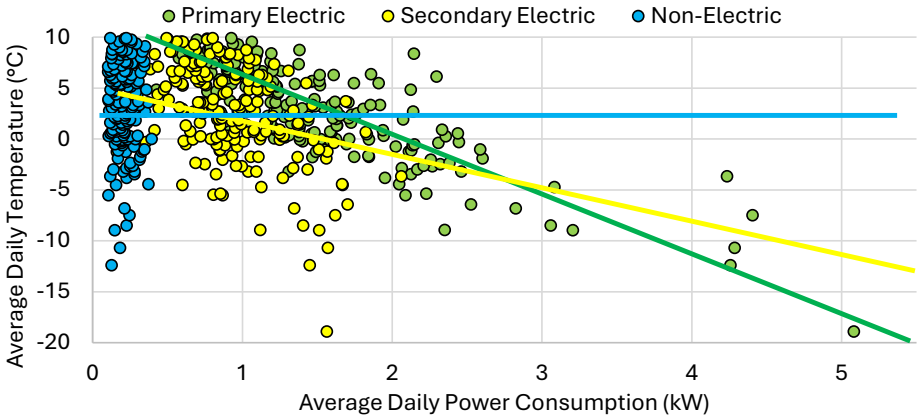
Model Commentary

- TOU volumetric rates effective November 1, 2024
- Includes 2025 riders
- AMI data domain: January 1 – December 31, 2024 inclusive
- Structural bill change = -1.1% note that technical sessions filed in 2024/2025 application reported a structural bill change of -1.7%[1]



[1] 20240731 NSPI to NSUARB Time-Varying Pricing 2024-2025 Application, Appendix C, Attachment 8, Page 19 of 39

Space Heating Flag



2023 Classification

Category	% of Customers	# of Customers
Primary Electric	38.5%	158,656
Secondary Electric	16.0%	65,941
Non-Electric	43.4%	178,887
Inconclusive	2.2%	8,915

Commentary

- The model uses AMI consumption data and Environment Canada[1] weather data to classify customers into each category.
- Historical use of rate codes to define space heating type is shown to only be **61%** in agreement with the correlation model.
- The discrepancy occurs primarily in Rate Code 02 and is likely due to increased rates of electrification relative to de-electrification across the rate class.

[1] https://weather.gc.ca/forecast/canada/index_e.html?id=NS

Methodology Changes
Space Heating Segmentation

Methodology changes were developed in consultation with Econoler

	Existing method	Proposed change	Projected Benefit
1	Neighbourhood criteria based on feeder and postal code combination	Neighbourhood criteria to be based on region (i.e. Northern, Eastern, Central and Western)	Increased pool of potential Control:Treatment matches will improve load propensity scores
2	E1 program participation balancing completed post control group selection	E1 programming will be included in control group selection process. Contingent on E1 approval to share data directly with NS Power	Improved load propensity score in final Control:Treatment matches and streamlined control group selection process
3	Heating classification applied post control group selection	Heating classification will be included in control group selection process	Improved load propensity score in final Control:Treatment matches by heating segment
4	Heating classification applied to all hours in pre and post period	Heating classification will be done using overnight off-peak hours	Load impact results will more accurately represent the effect of TVP by heating segment

Avoided Cost Modeling

- Customer benefits calculated using avoided cost values will be recalculated to reflect the updated Demand Side Management (DSM) Avoided Cost series from August 2024.
- The most recent avoided cost of energy series from the DSM Advisory Group (DSMAG) uses a Winter peak period definition that differs from the TVP program.
- The differences in winter peak periods are:
  - Reduced winter on peak months
  - Extended peak hours during winter months
  - Weekdays only
- Although these changes are not fully aligned with existing TVP program winter peak periods they remain a useful tool in calculating avoided costs.

Table 1: Comparison of season period definitions

	Season definitions used in June 12, 2024 analysis	Updated season definitions
Winter On-Peak	Months: Jan, Feb, Mar, Nov, Dec Days of the week: All days Time Periods: 7 am to 11 am, 5 pm to 9 pm	Months: Jan, Feb, Dec Days of the week: Weekdays only Time Periods: 6 am to 10 pm
Winter Off-Peak	Months: Jan, Feb, Mar, Nov, Dec Days of the week: All days Time Periods: 12 pm to 4 pm, 10 pm to 6 am	Months: Jan, Feb, Dec Weekdays: 10 pm to 6 am Weekends: All hours
Non-Winter	Months: Apr, May, Jun, Jul, Aug, Sep, Oct No on-peak/off peak differentiation	Months: Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov No on-peak/off peak differentiation

MURB TOU Pilot Tariff Updates

- In the 2024/25 Areas of Focus Work Plan, NS Power included:

  "Any MURB rate adjustments or refinements will be proposed to the stakeholder's group once sufficient data is available and analysis has been completed."

- NS Power will review and provide preliminary mid-year results for the MURB TOU Pilot Tariff as part of the Year Four Evaluation Report
  - Since this is a year-round rate, the results will be limited to the first winter period. Full year results will be available in the Year Five Evaluation Report.
- To date, there are 10 participating MURBs representing 941 units on the Pilot Tariff.

Current Metering & Systems Capabilities

- Current systems are built around existing standard offer rates with alternative rates requiring programming and testing to implement.
- More complex rates that vary from the framework of existing three-part energy TVP rates are possible with programming and testing.
- The level of effort on implementing each rate is dependent on the complexity of the rate and the anticipated scale of enrolment.
- The current state of TVP rates are:
  - CPP rates are implemented in all existing systems with some manual and partially automated processes remaining around enrolment, event calling, and notifications.
  - The existing TOU rate with 3 energy blocks is implemented in all existing systems with some manual and semi automated processes remaining around enrollment.
  - The MURB rate with 5 energy blocks requires manual intervention for the accounts enrolled on this rate. Further programing and automations will be required to scale this rate.

Current Metering & Systems Limitations

- The existing Customer Information System (CIS) is the most challenging to update and integrate due to its age and lack of product support. A capital project to replace CIS is under development.
- NS Power's current billing and metering systems do not have the ability to preform the following without extensive programming, upgrades, manual intervention, or difficult to scale alternative solutions:
  - Net metering on time-varying rates.
  - Time-varying or multi part demand charges.
  - More then three-time differentiated energy blocks per year.
  - New system integrations.

Potential Tools to Monitor Revenue Impacts

- During the 2023/24 (Year 3) stakeholder engagements, NS Power provided a draft rate design scorecard that was reviewed with stakeholders and modified to reflect feedback and learnings captured throughout the year
  - The scorecard (provided on the next slide) was used to assess various metrics of existing and modeled (modified or new) tariff/rate options across several categories (i.e. Customer Orientation, Encourage Efficient Operations, Fair Value, Accessibility, Customer Equality, and Revenue Neutrality)
- In addition to the rate design scorecard, the Company has set tariff enrolment targets which are intended as goals, aimed to meet the demand response targets for the TVP rates as shown in the Load Forecast Report
- While enrolment targets are intended as goals, these targets can be exceeded, by modest amounts, if there is sufficient customer interest and provide a mechanism for the Company to manage onboarding new participants in a controlled manner
  - With a fixed number of participants, it becomes easier to analyze the impact of TVP tariffs on revenue; NS Power can compare the revenue generated from TVP participants against those on standard tariffs to assess the effectiveness of the program

Potential Tools to Monitor Revenue Impacts – Rate Design Scorecard Rubric

Item	Objective	0 - Does Not Meet Objectives	1 - Meets Some Objectives	2 - Meets Most Objectives	3 - Meets All Objectives
Customer Orientation	The Tariff should be oriented to customers, maintaining simplicity while providing customer choices *Normalization Note* *Change from Base ≥ 10%* *a) Off-Peak: +/- 1 point* *b) Peak: +/- 1 point*	Tariff does not meet any of the 3 criteria: (1) easy to understand, (2) has attractive pricing differentials, and (3) provides customers with rate choice.	Tariff meets one of 3 criteria: (1) easy to understand, (2) has attractive pricing differentials, and (3) provides customers with rate choice.	Tariff meets two of 3 criteria: (1) easy to understand, (2) has attractive pricing differentials, and (3) provides customers with rate choice.	Tariff meets all 3 criteria: (1) easy to understand, (2) has attractive pricing differentials, and (3) provides customers with rate choice.
	The Tariff has demonstrated customer interest	<50% of Enrolment Target is met OR <10% of Customers Surveyed indicate interest	50-74.9% of Enrolment Target is OR ≥10% of Customers Surveyed indicate interest	75-99.9% of Enrolment Target is met OR ≥30% of Customers Surveyed indicate interest	100% of Enrolment Target is met OR ≥50% of Customers Surveyed indicate interest
Encourage Efficient Operations ***Informed by IRP and internal undertakings***	The Tariff should encourage system efficiency gains through load shifting potential and peak periods aligned with system peak and cost of service	<50% of peak periods are aligned with system peak	50-75% of peak periods are aligned with system peak	75-90% of peak periods are aligned with system peak	≥90% of peak periods are aligned with system peak
Fair Value	Customers load shift should be reflected in bill savings	No significant difference between customer load shift and structural savings (<1%)	Load shift customer savings exceed structural customer savings by ≥1%	Load shift customer savings exceed structural customer savings by ≥5%	Load shift customer savings exceeds structural customer savings by ≥10%
	Customers should experience annual savings compared to the standard offer rate	No annual load shift savings (<1%)	Annual load shift savings ≥1%	Annual load shift savings ≥5%	Annual load shift savings ≥10%
	Tariff volumetric rates correlate to marginal cost of electricity (i.e. largely fuel)	Volumetric rates do not reflect marginal cost of electricity. No correlation. Correlation coefficient < 0.1	Weak statistically significant correlation. Correlation coefficient ≥ 0.1	Statistically significant correlation. Correlation coefficient ≥ 0.2	Strong statistically significant correlation. Correlation coefficient ≥ 0.4
Accessibility	The Tariff should remain affordable and accessible to vulnerable sub populations	Tariff is not affordable or accessible to vulnerable sub populations	Tariff is affordable and accessible to vulnerable sub populations with many exceptions	Tariff is affordable and accessible to vulnerable sub populations with a few exceptions	Tariff is affordable and accessible to vulnerable sub populations
Customer Equality	The Tariff should aspire for a balance of 50/50 Structural Winners and Structural Losers.	Under 10% are either Structural Winners or Losers	Tariff achieves balance +/- 30% (i.e. Structural Winners 20-80%)	Tariff achieves balance +/- 20% (i.e. Structural Winners 30-70%)	Tariff achieves balance +/- 10% (i.e. Structural Winners 40-60%)
Revenue Neutrality	The Tariff should be revenue neutral without recognition of the value of load shifting for fairness across the rate class	Structural analysis indicates average bill change greater than +/- 10%	Structural analysis indicates average bill change less than +/- 10%	Structural analysis indicates average bill change less than +/- 5%	Structural analysis indicates average bill change less than +/- 1%

2024/25 Enrolment Targets

Enrolment targets are based off of the annual Demand Response targets as provided in the 2024 Load Forecast Report

Year	TVP Rate(MW)
2024	2
2025	4
2026	12
2027	22
2028	32
2029	36
2030	35
2031	35
2032	34
2033	34
2034	33

Source: 2024 Load Forecast Report Figure 56

Rate	Load Reduction per Customer (kW)	Winter 2024/25 Targets	Total Effective on Peak Reduction (MW)
Residential TOU	0.1925*	7,000	1.35
Residential CPP	0.7000*	3,500	2.45
MURB TOU	0.1800**	1,000 units (10 House Meters)	0.18
Total			**4.0**

*Load Shift based on Year 2 EM&V
**hypothetical load reduction per apartment unit from Integral report (reference tables 7 & 12)

2025/26 Proposed Enrolment Targets

Enrolment targets are based off the annual Demand Response targets as provided in the 2024 Load Forecast Report

Year	TVP Rate(MW)
2024	2
2025	4
2026	12
2027	22
2028	32
2029	36
2030	35
2031	35
2032	34
2033	34
2034	33

Source: 2024 Load Forecast Report Figure 56

Rate	Load Reduction per Customer (kW)	Winter 2025/26 Proposed Target	Total Effective on Peak Reduction (MW)
Residential TOU	0.1535*	20,500	3.1
Residential CPP	0.8555*	10,000	8.6
MURB TOU	0.1800**	1,500 units (15 House Meters)	0.3
Total			**12.0**

*Load Shift based on Year 3 EM&V

**hypothetical load reduction per apartment unit from Integral report (reference tables 7 & 12)


Nova Scotia
POWER
An Emera Company
TVP Tariff Marketing & Recruitment
2024/25 (Year 4) Update
32

TVP TARIFF MARKETING & RECRUITMENT

Summary

TVP Year 4 brought **innovation, success, learnings and opportunities**.

Although, we didn't reach our enrollment targets, we **welcomed over 6,000 new participants** which brought the **total enrollment to over 8,860 customers.** This is a **189% increase** in total enrollment from the previous year**.**

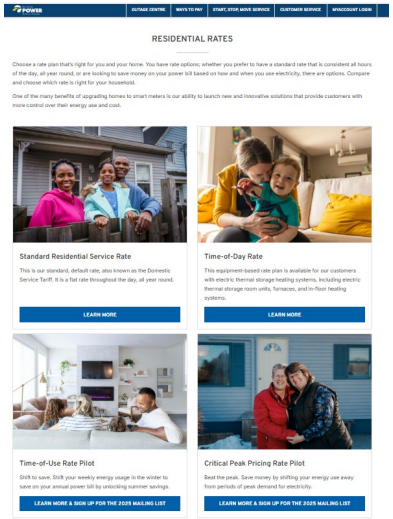
HIGHLIGHTS:

- Launched new rates branding
- Optimized and enhanced website experience
- Improved application process with Salesforce integrations
- Advanced and targeted email strategy
- Amplified customer reach & engagement with multi-channel paid outreach
- Introduced reporting and analytics (behaviour tracking and dashboards)
- New insights into next year's approach

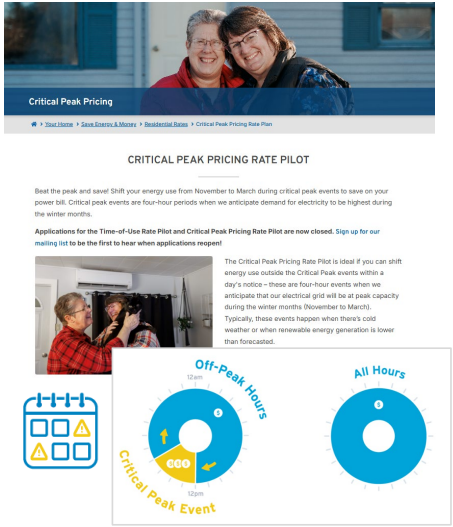


TVP TARIFF MARKETING & RECRUITMENT

New Rate Pages and Branding



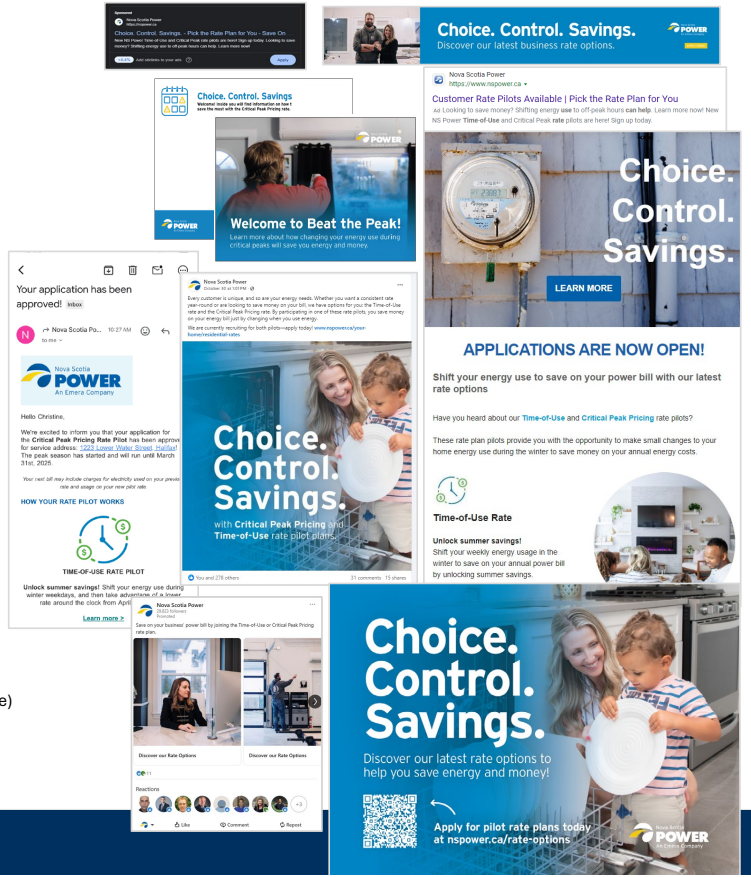




TVP TARIFF MARKETING & RECRUITMENT

Tactics and Schedule

- **Email – October 22 – December 13**
  - Introduced Retargeting and Segmentation/Personalization
- **Paid Channels – October 21 – November 30, Extended until December 2**
  - Direct Mail Postcard
  - Digital Ads - Social, Google/Bing Display, Reddit, LinkedIn (SMB Only)
  - Paid Search – Google and Bing
  - Chamber Ads – Yarmouth and Cape Breton
- **Owned Channels – October 21 - December 15**
  - Web - Updated Content and Imagery
  - nspower.ca Home Page Banner
  - Time-of-Use Blog (which was featured in Nov/Dec E-Bills)
  - Social Media Posts
- **Internal Comms – October 3 – December 13**
  - Power to Learn (Webinar)
  - PowerGram (Internal Newsletter) and Digital Screens
  - Internal Referral Program
- **Earned Media – November 26** *(pitches begin)*
  - Radio - Info Morning Cape Breton Interview
- **Onboarding, Retention & Engagement**
  - Welcome Email (Automated)
  - TOU and CPP Residential Mailed Welcome Packages (delayed due to strike)
  - Engagement Emails (Tips and Progress)
  - Exit survey of past participants
  - *And much more! (more details in the appendix)*



TVP TARIFF MARKETING & RECRUITMENT

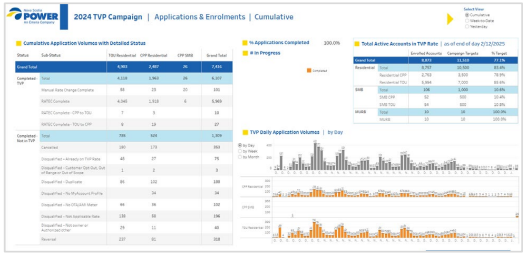
Reporting and Analytics

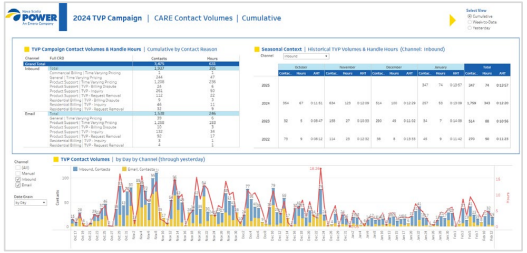
Over the last year, our business's marketing practices have advanced with the implementation of measurement models designed to effectively measure campaign performance.

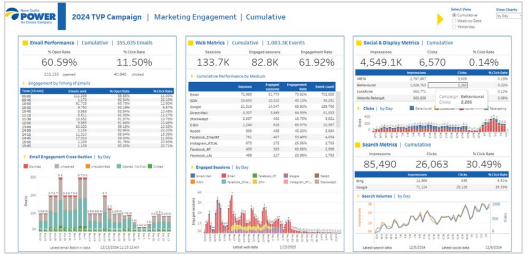
As a result of this work, we introduced multi-level, multi-touchpoint metrics & data capturing for Year 4 recruitment, to efficiently monitor success.

RESULTS:

- Developed dashboards to monitor TVP recruitment, in real-time, which included metrics on applications, volume of TVP related inquires, and marketing efforts.
- Cross-functional teams were able to leverage this data to stay agile, which helped inform daily decisions on recruitment efforts.







Summary of Residential Recruitment Key Contacts

HIGHLIGHTS:

- Email generated 87% of new participants.
- The decrease in Average Time on Landing page is small and likely due to content updates being more efficient for the reader.
- Paid Search, Display, Reddit Ads outperformed industry benchmarks.
- Direct Mail had the longest lifespan – and still brings in web traffic to date.

Residential	YEAR 1	YEAR 2	YEAR 3	YEAR 4	
Email					YOY %
Emails Recipients	43,280	19,489	112,089	355,035	217% ↑
Email Opens	21,778	10,855	71,011	215133	203% ↑
Open Rate	50%	56%	63%	68%	8% ↑
Total Clicks	5,004	4,120	14,817	40,845	176% ↑
Click Rate	23%	38%	21%	19%	-9% ↓
Conversion to Completed Application	N/A	N/A	N/A	87%	N/A
Web					
Total Views of Landing Pages	39,951	27,507	31,149	**98,909**	218% ↑
Total Average Time on Landing Pages	3m 41s	3m 55s	2m 47s	**2m 26s**	-9% ↓
TOU Landing Page Views				39,675	
Average Time on Page				2m 48s	
CPP Landing Page Views				32,627	
Average Time on Page				2m 21s	
Paid Search					
Google					
Impressions	N/A	N/A	9,079	69,722	87% ↑
Clicks	N/A	N/A	3,037	24,541	88% ↑
Click Through Rate (CTR)	N/A	N/A	33%	35.20%	5% ↑
Bing *NEW*					
Impressions	N/A	N/A	N/A	13,351	
Clicks	N/A	N/A	N/A	868	
Click Through Rate (CTR)	N/A	N/A	N/A	6.50%	
Paid Digital Ads (Display, Instagram, Facebook and Reddit)					
Impressions	N/A	3,084,248	N/A	4,744,260	
Clicks	N/A	14,483	N/A	7,534	
Click Through Rate (CTR)	N/A	0.60%	N/A	0.16%	
Direct Mail *NEW*					
Reach	N/A	N/A	N/A	200,000 homes	
Total Views of Landing Pages	N/A	N/A	N/A	7,729	
Average Time on Page	N/A	N/A	N/A	3m 39s	
Results					
Enrolment Target	1,000 TOU / 500 CPP	1,000 TOU / 500 CPP	2,000 TOU / 1,000 CPP	7,000 TOU / 3,500 CPP	
Applications Received	991 TOU / 351 CPP	474 TOU / 183 CPP	2,173 TOU / 837 CPP	4,097 TOU / 2,487 CPP	
Pilot Enrolment	667 TOU / 275 CPP	931 TOU / 384 CPP	2,000 TOU / 1,000 CPP	5,977 TOU / 2,756 CPP	
% of Target Achieved	76% TOU / 60% CPP	93% TOU / 77% CPP	100% / 100% CPP	85% TOU / 79.0% CPP	

Summary of Business Recruitment Key Contacts

HIGHLIGHTS:

- Although email opens/clicks decreased YoY (Y3/Y4), the click rate doubled – meaning the targeted content was more engaging.
- CTR for search is significantly high suggesting that while search volume is lower, business users demonstrate higher intent and engagement when they do search online.
- Overall YoY decreases resulted from focusing on non-digital tactics which resulted in less digital traffic but more successful results.

Business	YEAR 1	YEAR 2	YEAR 3	YEAR 4	
Email					**YOY %**
Emails Recipients	4,136	6,914	6,216	503	-1136% ↓
Email Opens	1,729	3,254	3,264	236	-1283% ↓
Open Rate	42%	47%	53%	47%	-12% ↓
Total Clicks	189	445	324	59	-449% ↓
Click Rate	11%	14%	10%	25%	60% ↑
Web					
Total Views of Landing Pages	39,951	27,507	31,149	18,978	-64% ↓
Total Average Time on Landing Pages	3m 41s	3m 55s	2m 47s	1m	-60% ↓
Paid Search					
Google					
Impressions	N/A	N/A	9,079	1,402	-548% ↓
Clicks	N/A	N/A	3,037	587	-417% ↓
Click Through Rate (CTR)	N/A	N/A	33%	41.87%	20% ↑
Bing *NEW*					
Impressions	N/A	N/A	N/A	1,015	
Clicks	N/A	N/A	N/A	67	
Click Through Rate (CTR)	N/A	N/A	N/A	6.60%	
Paid Digital Ads (Google Display and LinkedIn)					
Impressions	N/A	995,163	N/A	5,725,826	
Clicks	N/A	1,483	N/A	30,412	
Click Through Rate (CTR)	N/A	0.15%	N/A	0.51%	
2024 Q4 - Contactor Newsletter					
Email Recipients	N/A	N/A	129	170	
Chamber of Commerce Newsletters / Advertising					
Yarmouth Chamber of Commerce	N/A	N/A	N/A	Over 300 members	
Cape Breton Chamber Reach	N/A	N/A	N/A	3,100 subscribers	
Results					
Enrolment Target	1,000 TOU / 1,000 CPP	1,000 TOU / 1,000 CPP	1,000 TOU / 1,000 CPP	1,000 TOU / 1,000 CPP	
Applications Received	33 TOU / 10 CPP	25 TOU / 8 CPP	35 TOU / 7 CPP	0 TOU / 26 CPP*	
Pilot Enrolment	29 TOU / 9 CPP	40 TOU / 9 CPP	62 TOU / 10 CPP	54 TOU / 53 CPP	
% of Target Achieved	3% TOU / 1% CPP	4% TOU / 1% CPP	6% TOU / 1% CPP	5% TOU / 5% CPP	

*** Please note: In some cases, one (1) application may have been submitted for multiple SMB accounts.**

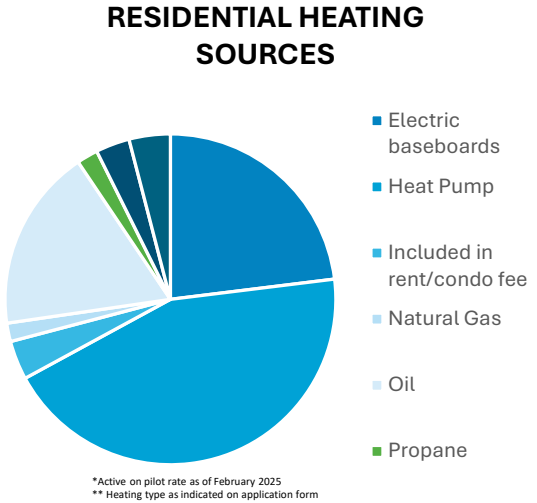
TVP TARIFF MARKETING & RECRUITMENT

Residential Recruitment

	TOU (Rate 80, 81)	CPP (Rate 70, 71)	Residential Total
Enrollment Target	7,000	3,500	10,500
Year 4 New Applications	4,903	2,248	7,151
Year 4 Accepted New Applications	4,097	2,487	6,584
Current Enrollment (As of March 4, 2025)	5,977	2,756	8,733

HIGHLIGHTS

- 83% of the Residential Enrollment Target was achieved
  - 85% of TOU Rate target
  - 79% of CPP Rate target
- Of the approved participants, approximately 11% meet the Low-Income Cutoff (LCL).
- 85% of participants agreed to participate in surveys throughout the pilot.
- Close to 67% of pilot participants identified they heat their homes electrically (i.e., baseboards, heat pump) on the application form. This is a 1% increase from last year.



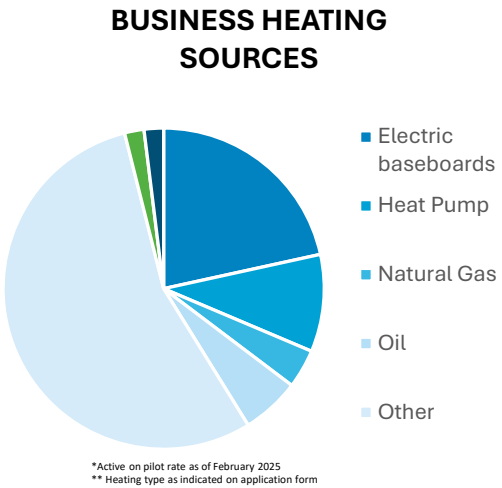
TVP TARIFF MARKETING & RECRUITMENT

SMB Recruitment

	TOU (Rate 82, 83)	CPP (Rate 72, 83)	Commercial Total
Enrollment Target	1,000	1,000	2,000
Year 4 New Applications	0	26	26
Current Enrollment (As of March 4, 2025)	54	53	107

HIGHLIGHTS

- New participants from 2025 came from our Business Solutions team. Our Commercial Advisors leveraged the TVP rates in customer conversations.
  - This customized recruitment approach will be utilized in year 5 as it appears to be the key to SMB Recruitment.
- 10% of Business Enrollment Targets were achieved.
- The top business sectors the pilot participants belong to: Retail Stores, Recreation, Restaurants, Automotive, Accommodation
- Close to 31% of pilot participants identified they heat electrically (i.e., baseboards, heat pump) on the application form. This is a 34% decrease from last year.
- 84% of participants agreed to participate in surveys throughout the pilot.



TVP TARIFF MARKETING & RECRUITMENT

MURB Recruitment

	MURB Rate
Enrollment Target	10
Year 4 New Applications	10
Current Enrollment (As of January 9, 2025)	10

HIGHLIGHTS

- 100% of the MURB Enrollment Target was achieved
  - 10 General Demand house meter customers were recruited for the Pilot
  - These buildings are representative of ~1000 residential suite meters
- Recruitment was conducted through direct outreach to customers, many of whom participated in the MURB Stakeholder Sessions in 2024.
- NS Power's Customer Solutions team worked directly with MURB stakeholders to analyze their buildings' potential to shift load.
- Pilot participants are representative of a variety of heating and domestic hot water systems including:
  - Air to Water Heat Pumps
  - Hot Water Baseboard
  - Natural Gas Boilers
- Pilot participant building sizes range from <50 units to >200 residential units

TVP TARIFF MARKETING & RECRUITMENT

Year 4 – Challenges and Opportunities

CHALLENGES

- **Canada Post Strike –** Limited ability to push larger batches of customer outreach due to Customer Care Centre focused on Canada Post campaign. Additionally, marketing could not complete any subsequent direct mail drops which proved to be a successful tactic.
- **Timeline -** As approval was given to extend the Pilot for Year 4 in late October, recruitment started later than expected. It progressed into the season adding some complications and applications dipped leading into the holidays.

OPPORTUNITIES

- **SMB Recruitment –** Traditional marketing efforts showed inefficient for SMB recruitment. Conversations with trusted advisors (NS Power Commercial Advisors) proved to be the most effective tactic.
- **Channels & Timing –** Longer lead times and recruitment periods to drive more interest and applications, in addition to adding more marketing channels and touchpoints with customers.

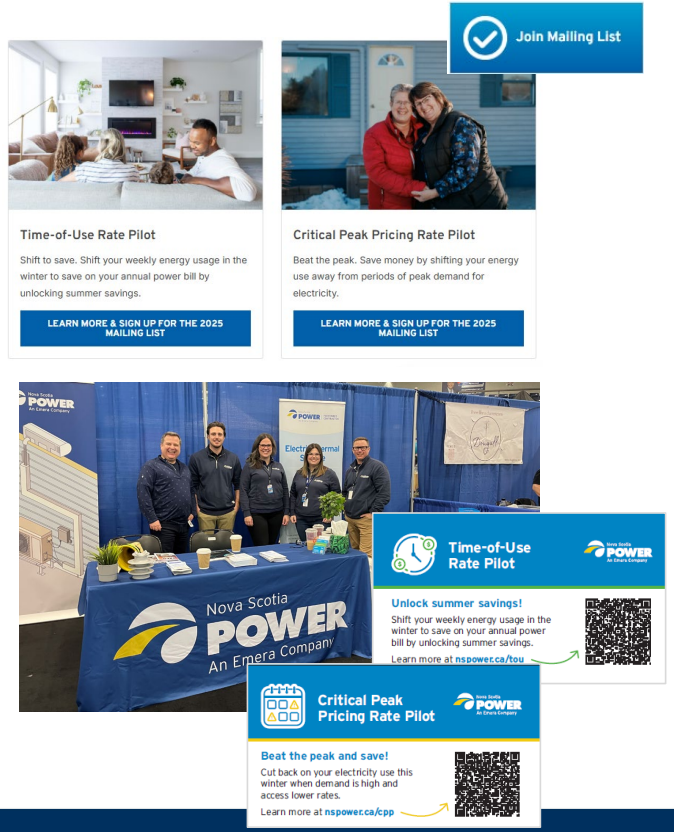
TVP TARIFF MARKETING & RECRUITMENT

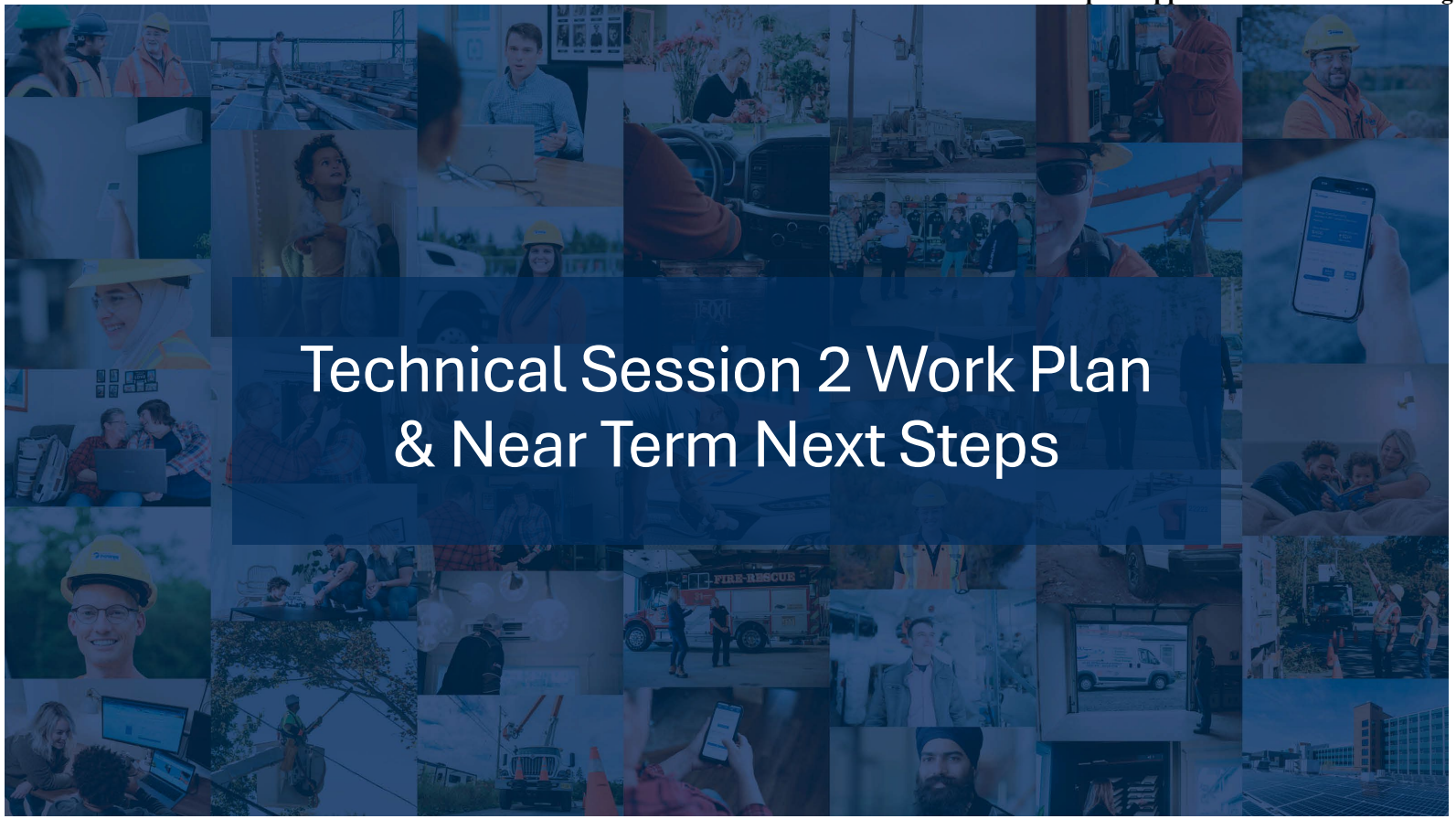
Closing Thoughts

As a result of Year 4 learnings, the team will continue to adapt and evolve our engagement and recruitment efforts to deliver value for our customers.

We will:

- Continue to encourage sign-ups for the TVP mailing list on our rate pilot landing pages through customer conversations and public events. **There are currently over 650 Customers signed up.**
- Roll out ongoing customer engagement plans to maintain retention and demonstrate value to our pilot customers.
- Grow awareness, consideration and sign-ups for our TVP rates to our standard residential customers.
- Continuously improve application process and marketing efforts, we have conducted an exit survey for those who left the rate pilot. These findings will be presented and considered in Year 5 planning.




Technical Session 2 Work Plan
& Near Term Next Steps
FIRE-RESCUE

2024/25 Areas of Focus Work Plan (1/2)

Technical Session 2 – anticipated late-March/early-April

Summary of 2024/25 Areas of Focus & Board Directives	Type	Items to be Discussed/Reviewed
3.0 – Demand Charges • (3.1) evaluate the extent to which the demand charge may act as a barrier to General class TOU participation and continue to evaluate non-demand TVP designs for General Service customers • (3.2) assessment of demand charge impacts on General Service customers and evaluation of demand charge modifications or alternatives for TVP offerings to General Service customers • (3.3) evaluate the level of costs that are truly driven by an individual's non-coincident demands (e.g. an individual customer's transformer), and only recover those costs through a non-coincident demand charge. All other demand-related costs should be recovered through either an on-peak volumetric charge or a demand charge that only applies during on-peak hours • (3.4) complete a performance assessment of the General Service Class customers, as described in Synapse's evidence, evaluating the extent that bills increase as they shift load from on-peak hours to off-peak hours. It is expected that this assessment will identify whether the demand charge increases the electricity bills for these participants. If the assessment finds that the demand charge results in higher bills to the commercial class customers shifting their load from on-peak to off-peak, NS Power is to assess removal of the demand charge, as well as any other changes, which could incentivize the participation of the commercial rate class customers in the TVP Program.	BD	• Prepare summary of how demand charges are currently implemented and billed, for instance: demand charge, first energy block. • Comparison of pricing demand in TVP versus standard offer tariffs • Examine availability of data and cost drivers to determine individual customer cost impacts and potential of TVP to influence • Discussion of scoping in relation to item 3.3 • Identify impact load shifting may have on demand charges for existing General rate customers (through performance assessment) and examination of alternative demand applications • Compile sample data using AMI meters to review correlation of General customers' demands to system peaks

2024/25 Areas of Focus Work Plan (2/2)

Technical Session 2 (continued) – anticipated late-March/early-April

Summary of 2024/25 Areas of Focus & Board Directives	Type	Items to be Discussed/Reviewed
4.0 – Reporting on Small Business Customer Items • (4.1) report to stakeholders on changes that could be made to help customers determine whether they will benefit from TVP	CA	• Analysis of general load characteristics of small business customers that may shift load in response to TVP • Information on commercial/small business customer recruitment and customer outreach. • Explore opportunities that could allow customers to be classified by business sector and provide an update on these efforts • Summary of specific reasons why customers are reluctant to participate, followed by an evaluation of the pilot tariff to see if changes can address some of the concerns



Near Term Next Steps

- Thu, 27 Feb – NS Power circulated slides
- Mon, 3 Mar – Technical Session 1
- Fri, 14 Mar – stakeholders provide comments on this deck, including the Work Plan for the upcoming Technical Session 2, to NS Power
- Late-March/early-April – NS Power schedule Technical Session 2

Nova Scotia POWER An Emera Company



Appendix

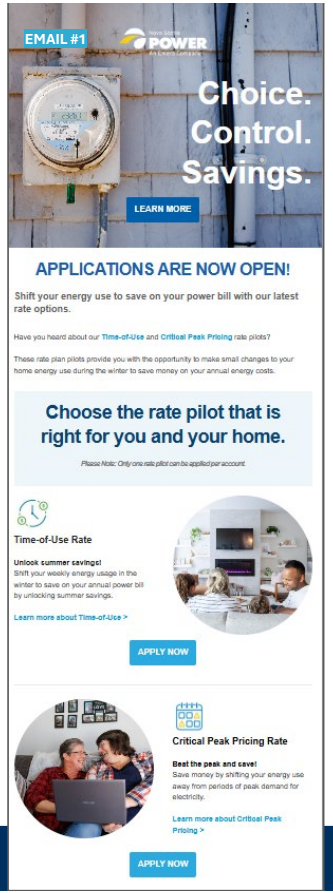
Marketing Tactics & Results

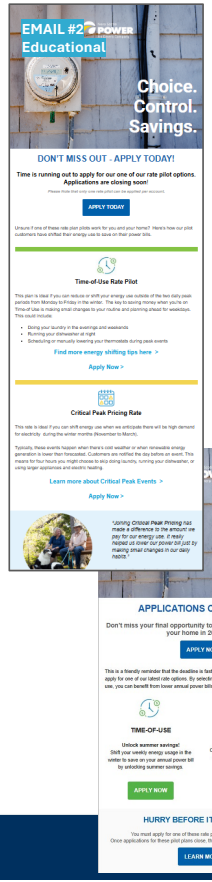
APPENDIX | MARKETING TACTICS & RESULTS

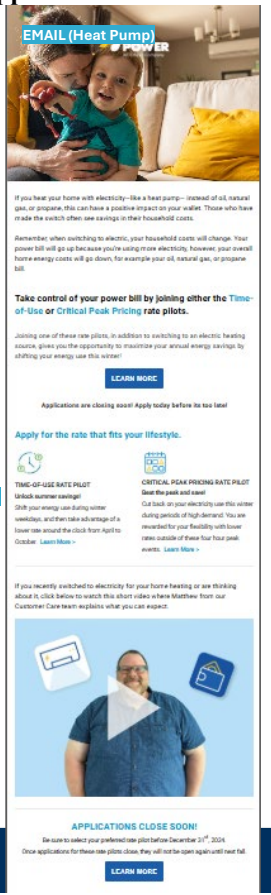
Email

Residential

- Strongest recruitment tactic, accounting for 87% of new participants in year 4.
- Ran from Oct 22 – Dec 15 and emailed over 355K Residential Customers.
- Highest Click Rate and Open Rate occurred with Email 2 – to a segment of customers who opened and engaged with Email 1 but didn't apply (Email #2 Educational)





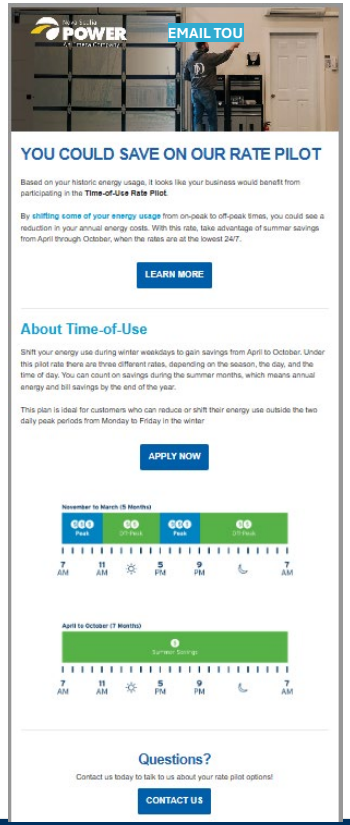


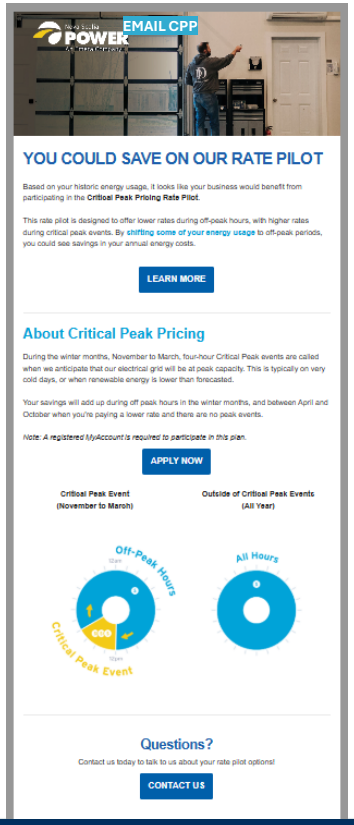
APPENDIX | MARKETING TACTICS & RESULTS

Email

Business

- Although sent to a small number of SMB customers, these were personalized. Which resulted in the highest Click Rate for SMB Emails.
- LEARN MORE and APPLY NOW were the most clicked CTAs



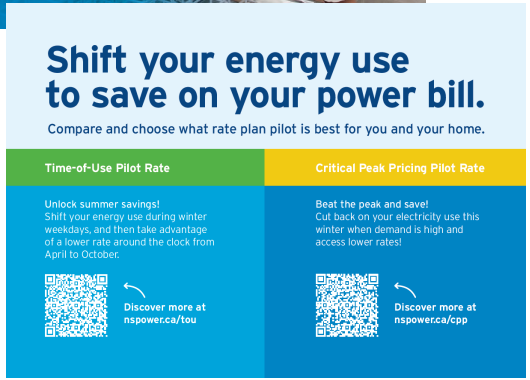


APPENDIX | MARKETING TACTICS & RESULTS

Direct Mail

- Second strongest marketing tactic.
- Recruitment postcard, sent as a Neighborhood Mail piece, reached 200,000 single-dwelling homes.
- This campaign generated 7,729 website sessions via the QR Code
- Traffic to the website still coming in daily even after recruitment.





APPENDIX | MARKETING TACTICS & RESULTS

Paid Digital Advertising

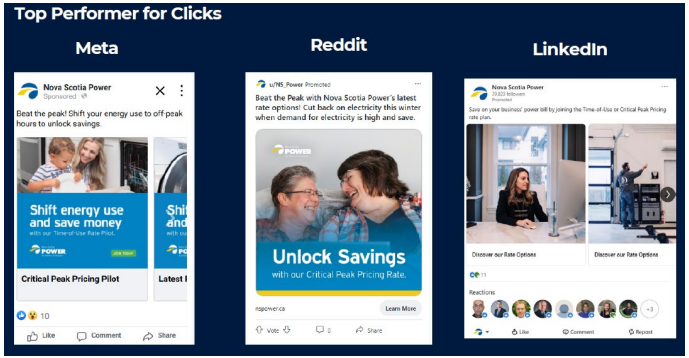
- Ran from October 21 – November 30, Extended until December 2

Residential

- SEM and Display
- Paid Social
  - Facebook
  - Instagram
  - Reddit

Business

- SEM and Display
- Paid Social
  - LinkedIn



Paid Display and SEM

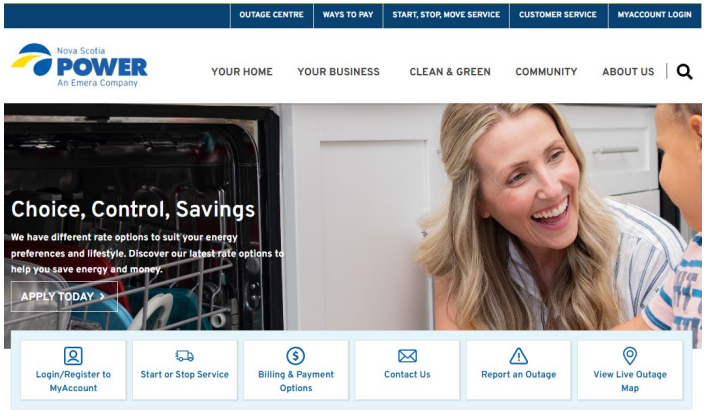


Paid Social



APPENDIX | MARKETING TACTICS & RESULTS

Website



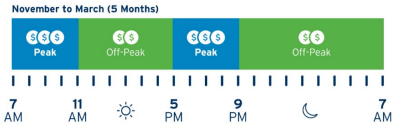
- Web Updates:
  - Individual Rate Pages Created
  - Content and Visuals Updates
- Increase webpage referrals
  - Save Energy and Money
  - Rate Options
  - Home Page Banner – November 28 – December 15, 2024

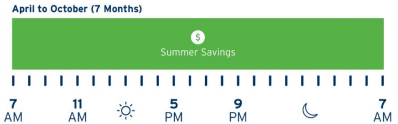
APPENDIX | MARKETING TACTICS & RESULTS

Residential Rate Branding

TIME-OF-USE RATE PILOT

nspower.ca/tou

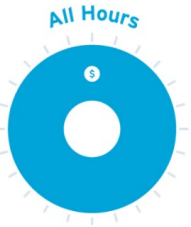




CRITICAL PEAK PRICING RATE PILOT

nspower.ca/cpp

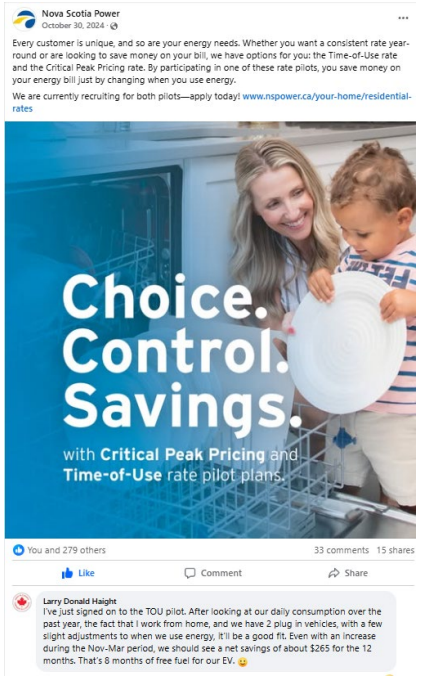


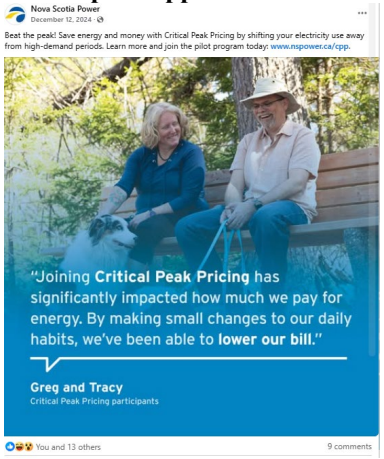


APPENDIX | MARKETING TACTICS & RESULTS

Social Media

- Social Media Posts - October 30, November 21 & December 12, 2024







APPENDIX | MARKETING TACTICS & RESULTS

SMB Engagement

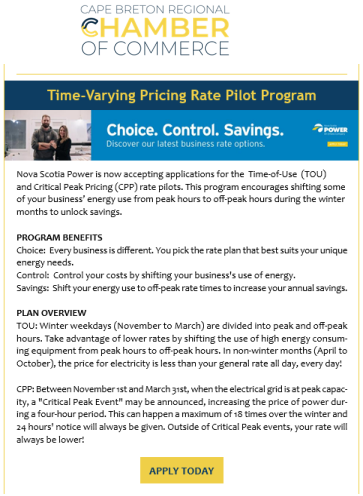
Chamber of Commerce

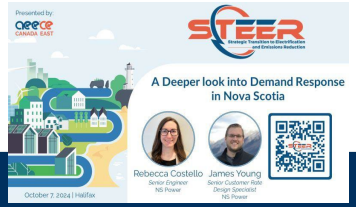
- We submitted content and banner ads to be featured in October issues of the Yarmouth Chamber of Commerce Bi-Weekly Newsletter and Cape Breton Chamber of Commerce Monthly.
- View Yarmouth Newsletter
- Copy of Cape Breton Newsletter available upon request

STEER Conference

- NS Power employees presented at the Association of Energy Engineers' STEER Conference. This generated great conversations with commercial building energy designers.





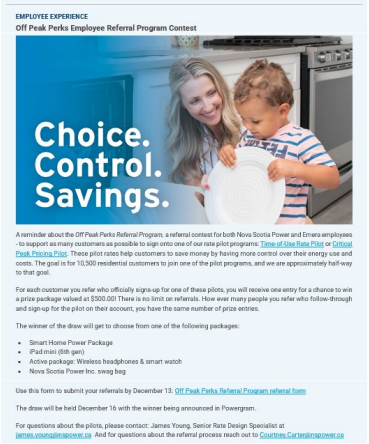


APPENDIX | MARKETING TACTICS & RESULTS

Internal Engagement

- Focus to increase word of mouth from NS Power employees to empower their ability to educate and explain the TVP Tariff program
- Power to Learn (Internal Webinar) – October 3, 2025
  - 220 Attendees
- PowerGram (internal newsletter) Feature – November 15, 2024
- Internal Referral Program – November 15 – December 13, 2024
  - 133 referrals documented from internal referral program




EMPLOYEE EXPERIENCE

Off Peak Perks Employee Referral Program Contest

A reminder about the *Off Peak Perks Referral Program*, a referral contest for both Nova Scotia Power and Emera employees - to support as many customers as possible to sign onto one of our rate pilot programs: Time-of-Use Rate Pilot or Critical Peak Pricing Pilot. These pilot rates help customers to save money by having more control over their energy use and costs. The goal is for 10,500 residential customers to join one of the pilot programs, and we are approximately half-way to that goal.

For each customer you refer who officially signs-up for one of these pilots, you will receive one entry for a chance to win a prize package valued at $500.00! There is no limit on referrals. How ever many people you refer who follow-through and sign-up for the pilot on their account, you have the same number of prize entries.

The winner of the draw will get to choose from one of the following packages:

- Smart Home Power Package
- iPad mini (6th gen)
- Active package: Wireless headphones & smart watch
- Nova Scotia Power Inc. swag bag

Use this form to submit your referrals by December 13: Off Peak Perks Referral Program referral form

The draw will be held December 16 with the winner being announced in Powergram.

For questions about the pilots, please contact: James Young, Senior Rate Design Specialist at james.young@nspower.ca And for questions about the referral process reach out to Courtney.Carter@nspower.ca

APPENDIX | MARKETING TACTICS & RESULTS

Welcome Packages

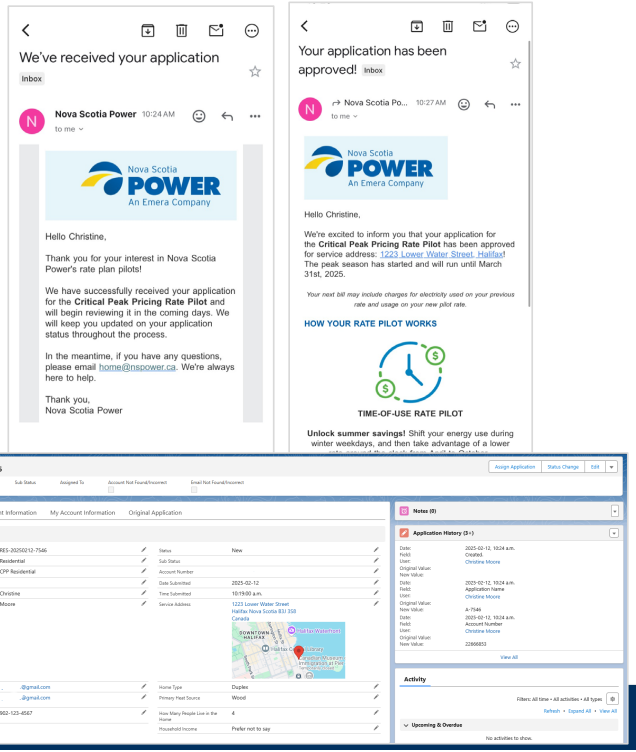
- Sent to over 8K customers
- Focused on providing a value add with helpful tips and tricks to be successful on the plans.
- A customer called in after receiving welcome package who just days before left the program. They said the welcome letter made a positive impact and now want to rejoin after getting the mail because they feel they understand the program better



APPENDIX | MARKETING TACTICS & RESULTS

Application Communication

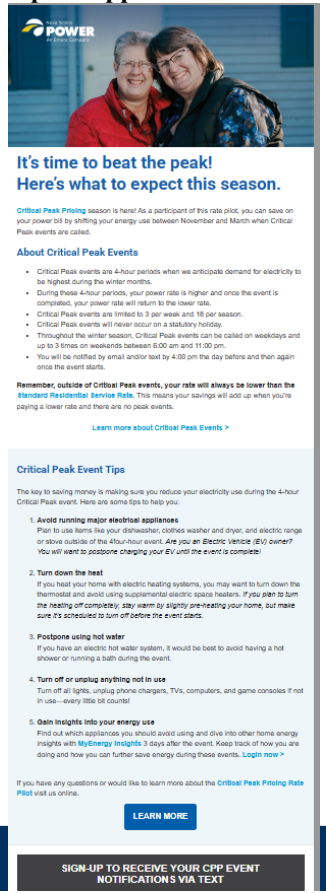
- Automated emails sent from Salesforce kept customers informed on the status of their application and reduced application processing time for customer care
- Integrations between TouchLogic and Salesforce for CPP event data and CPP rate data. Having these records helps resolve customer issues regarding event notifications



APPENDIX | MARKETING TACTICS & RESULTS

Engagement

- Sent a Critical Peak Event Prep Email
- Plan to send season complete email, and push more social media to help support



It's time to beat the peak!
Here's what to expect this season.

Critical Peak Pricing season is here! As a participant of this rate pilot, you can save on your power bill by shifting your energy use between November and March when Critical Peak events are called.

About Critical Peak Events

- Critical Peak events are 4-hour periods when we anticipate demand for electricity to be highest during the winter months.
- During these 4-hour periods, your power rate is higher and once the event is completed, your power rate will return to the lower rate.
- Critical Peak events are limited to 3 per week and 18 per season.
- Critical Peak events will never occur on a statutory holiday.
- Throughout the winter season, Critical Peak events can be called on weekdays and up to 3 times on weekends between 6:00 am and 11:00 pm.
- You will be notified by email and/or text by 4:00 pm the day before and then again once the event starts.

Remember, outside of Critical Peak events, your rate will always be lower than the Standard Residential Service Rate. This means your savings will add up when you're paying a lower rate and there are no peak events.

Learn more about Critical Peak Events >

Critical Peak Event Tips

The key to saving money is making sure you reduce your electricity use during the 4-hour Critical Peak event. Here are some tips to help you:

1. **Avoid running major electrical appliances**
   Plan to use items like your dishwasher, clothes washer and dryer, and electric range or stove outside of the 4four-hour event. *Are you an Electric Vehicle (EV) owner? You will want to postpone charging your EV until the event is complete!*
2. **Turn down the heat**
   If you heat your home with electric heating systems, you may want to turn down the thermostat and avoid using supplemental electric space heaters. *If you plan to turn the heating off completely, stay warm by slightly pre-heating your home, but make sure it's scheduled to turn off before the event starts.*
3. **Postpone using hot water**
   If you have an electric hot water system, it would be best to avoid having a hot shower or running a bath during the event.
4. **Turn off or unplug anything not in use**
   Turn off all lights, unplug phone chargers, TVs, computers, and game consoles if not in use—every little bit counts!
5. **Gain insights into your energy use**
   Find out which appliances you should avoid using and dive into other home energy insights with MyEnergy Insights 3 days after the event. Keep track of how you are doing and how you can further save energy during these events. Login now >

If you have any questions or would like to learn more about the Critical Peak Pricing Rate Pilot visit us online.

LEARN MORE

SIGN-UP TO RECEIVE YOUR CPP EVENT NOTIFICATIONS VIA TEXT


Nova Scotia
POWER
An Emera Company
TVP Tariff Pilot – Technical Session 2
April 7, 2025
1

Agenda

1. Welcome & Introduction
2. Review Work Plan for Today's Session
3. Demand Charges
4. Additional Income-based Investigation
5. Revisions to the Rate Design Scorecard
6. Reporting on Small Business Items
7. Technical Session 3 Work Plan & Near Term Next Steps

2024/25 Areas of Focus Work Plan (1/2)

For Discussion Today (Technical Session 2 of 3)

Summary of 2024/25 Areas of Focus & Board Directives	Type	Items to be Discussed/Reviewed
3.0 – Demand Charges • (3.1) evaluate the extent to which the demand charge may act as a barrier to General class TOU participation and continue to evaluate non-demand TVP designs for General Service customers • (3.2) assessment of demand charge impacts on General Service customers and evaluation of demand charge modifications or alternatives for TVP offerings to General Service customers • (3.3) evaluate the level of costs that are truly driven by an individual's non-coincident demands (e.g. an individual customer's transformer), and only recover those costs through a non-coincident demand charge. All other demand-related costs should be recovered through either an on-peak volumetric charge or a demand charge that only applies during on-peak hours • (3.4) complete a performance assessment of the General Service Class customers, as described in Synapse's evidence, evaluating the extent that bills increase as they shift load from on-peak hours to off-peak hours. It is expected that this assessment will identify whether the demand charge increases the electricity bills for these participants. If the assessment finds that the demand charge results in higher bills to the commercial class customers shifting their load from on-peak to off-peak, NS Power is to assess removal of the demand charge, as well as any other changes, which could incentivize the participation of the commercial rate class customers in the TVP Program.	BD	• Prepare summary of how demand charges are currently implemented and billed, for instance: demand charge, first energy block. • Comparison of pricing demand in TVP versus standard offer tariffs • Examine availability of data and cost drivers to determine individual customer cost impacts and potential of TVP to influence • Discussion of scoping in relation to item 3.3 • Identify impact load shifting may have on demand charges for existing General rate customers (through performance assessment) and examination of alternative demand applications • Compile sample data using AMI meters to review correlation of General customers' demands to system peaks

2024/25 Areas of Focus Work Plan (2/2)

For Discussion Today (Technical Session 2 of 3)

Summary of 2024/25 Areas of Focus & Board Directives	Type	Items to be Discussed/Reviewed
4.0 – Reporting on Small Business Customer Items • (4.1) report to stakeholders on changes that could be made to help customers determine whether they will benefit from TVP	CA	• Analysis of general load characteristics of small business customers that may shift load in response to TVP • Information on commercial/small business customer recruitment and customer outreach. • Explore opportunities that could allow customers to be classified by business sector and provide an update on these efforts • Summary of specific reasons why customers are reluctant to participate, followed by an evaluation of the pilot tariff to see if changes can address some of the concerns


3.0 – Demand Charges

Demand Charge Review

- **How Demand is measured for the General rate class:**
  - Demand is measured in 15-minute blocks every 5 minutes.
  - Maximum demand recorded in a billing period is used and reset for each billing period (no ratchet).

- **How Demand is charged:**
  - Demand is directly charged at a $10.554 per kW.
  - Demand is indirectly charged by scaling the size of the 1st energy block proportional to the measured demand.
    - The first energy block is for the first 200 kilowatt-hours per month per kilowatt of maximum demand.
  - For Example:
    - a customer with a demand of 10 kW will see their first 2,000 kWh charged to the 1st energy block with the remaining energy used charged to the 2nd energy block.
    - a customer with a demand of 25 kW will see their first 5,000 kWh charged to the 1st energy block with the remaining energy used charged to the 2nd energy block.

GENERAL SERVICE TARIFF (RATE 11)

DEMAND CHARGE

	Per month per kilowatt of maximum demand.
Effective February 2, 2023	$10.554
Effective January 1, 2024	$10.554

32 cents per kilowatt reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

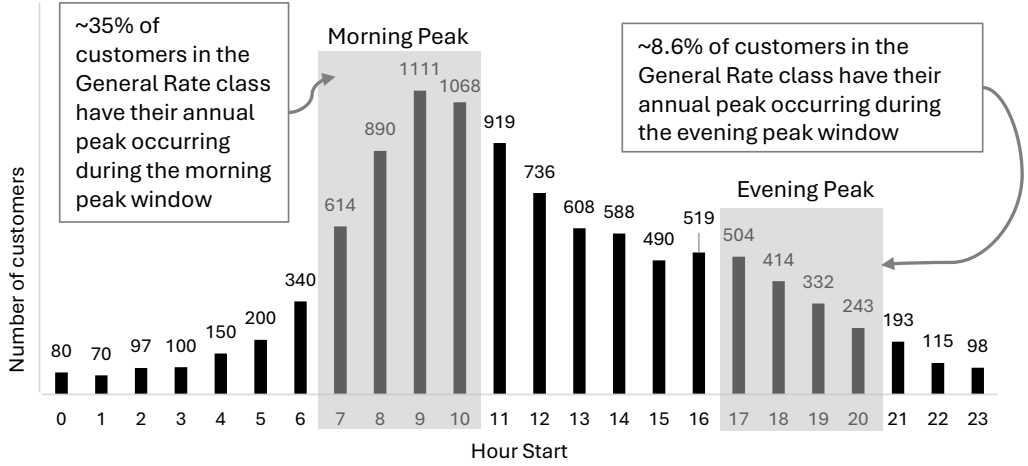
ENERGY CHARGE

	For the first 200 kilowatt-hours per month per kilowatt of maximum demand	For all additional kilowatt-hours
	Cents per kilowatt-hour	
Effective February 2, 2023	13.248	9.952
Effective January 1, 2024	14.287	10.990

GENERAL RATE CLASS

Distribution of Customer Winter Peak Interval Consumption by Hour of Day

The General Rate Class TOU rate aligns with 43.6% of customer winter peak consumption, enabling demand reduction for these customers. However, the remaining customers will see a winter peak demand increase by shifting load to the off-peak period



Model Commentary

Individual customer annual peak 15-minute interval occurrence is captured with the corresponding timestamp of that interval. For example, if Customer A achieved their winter peak interval consumption at 8:15 AM on Dec 14th 2024, Customer A would be counted in the 8 AM hour start bin in the provided distribution chart.

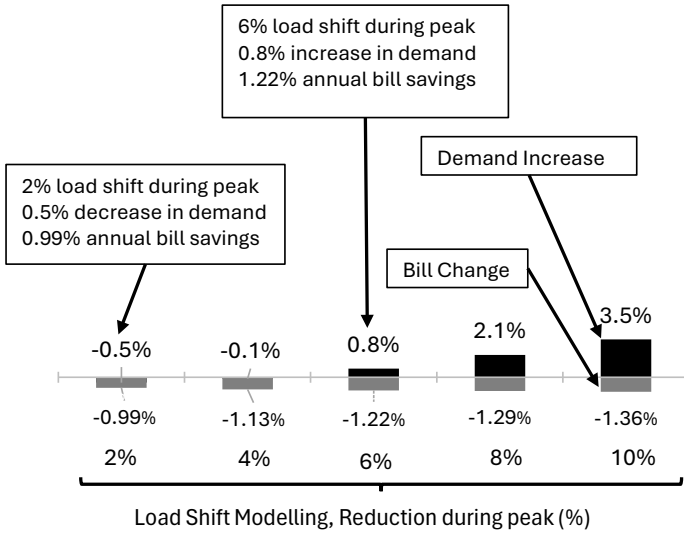
AMI data sample of 10,479 commercial customers in the General Rate Class currently on Rate 11.

Source: NS Power, AMI interval data, Nov 2023 – Mar 2024

ITEM 3.4 – GENERAL RATE CLASS, TOU TARIFF, CUSTOMERS WITH WINTER PEAK OCCURRING DURING PEAK TIMES (7-11 AM, 5-9 PM)

Impact on Demand & Annual Bill from TOU

On average customers shifting load from peak to off-peak hours experience demand increase with negligible increase in savings after shifting 6% or more of peak consumption to off-peak periods. Although customers are not financially penalized for shifting load beyond 6%, the increase in demand charge offsets the savings in energy costs.



Model Commentary

Energy neutral model assumes customers turn off electrical loads during peak and turn on an equivalent load that was displaced during off-peak hours that shoulder peak hours without concern for increasing demand.

Savings increase up to 1.67% at 10% load shift if energy shifted in a manor that does not increase demand (filling in valleys)

This analysis shows only a minor incentive to shift load under the current rate design. Although improvements to demand charges may improve bill savings for higher load shifts above 6% the lack of bill savings in the 4%-6% range is of primary concern which is not impacted materially by the demand charge structure.

AMI data sample of 4075 commercial customers in the General Rate Class currently on Rate 11 that experience their annual demand between 7-11 am and 5-9 pm.

TOU volumetric rates effective November 1, 2024. Includes 2025 riders.

Source: NS Power, AMI interval data, Jan 2024 – Dec 2024

ITEM 3.3

Non-coincident Demand Costs

- Note that COSS remains an open Matter before the Board (M11472) and much of COSS-related items remain under consideration within those processes.
- The conclusion of how costs are classified to demand inside of the COSS model between coincident demand, non-coincident demand, and energy will inform any time-varying of demand charges.
- Based on prior COSS models it would be reasonable to expect distribution costs, and a portion of other asset classes would be to attributed to non-coincident demand charges with the remainder attributed to either peak demand or mid peak demand charges in a multi-part or time-varying demand rate.

ITEM 3.3

Transformers in Cost of Service

- In cost of service “Line Transformers” under the distribution section, would serve individual customers or on occasion small groups of customers adjacent to reach other.
- In the case of General rate class customers, the size and voltage of General rate class customers typically limits the amount of transformer sharing that can occur with a one transformer to one customer being the typical configuration, unless multiple customers are co-located in a single facility.

ITEM 3.3

Proportion of Costs Classified as Demand Related

- The following ratios are based on total demand for the General rate class and include using the cost-of-service model from the 2023-2024 GRA (M11431).
- As noted, an updated cost of service model is currently being developed with demand allocation ratios being reviewed in that proceeding.

GENERAL CLASS (SOURCED FROM 2023-2024 GRA)

Function	Demand Allocation Ratios
Generation	59%
Transmission (HV & EHV)	14%
Distribution	28%
Total	**100%**

GENERAL RATE CLASS, TOU TARIFF

Proposal for General Rate Class TOU Modifications

The model indicates that the existing flat rate with demand is already effective to some degree in leading customers to improve their load factor. This can be seen with a majority of customers in this rate class are already producing average daily peaks outside the 4-hour morning and evening peak windows in the winter months.

The modeling work indicates that the existing TOU rate structure is not suitable for many businesses with coincident peaks to be financially rewarded from shifting load from peak to off-peak. Under 6% load shifting, bill savings occur from both the demand and energy components of the bill, but the total bill impact is minor. This indicates that, at the anticipated levels of load shift for a TOU customer, the current rate structure and/or pricing signal ratios of the existing TOU rate are the primary restrictions, independent of demand charge.

In order to achieve load shifting levels above 6%, revisions to the demand pricing structure should also be considered as a secondary improvement if not otherwise mitigated by technology to optimize demand.

Proposed alternative rate modeling to explore in future years

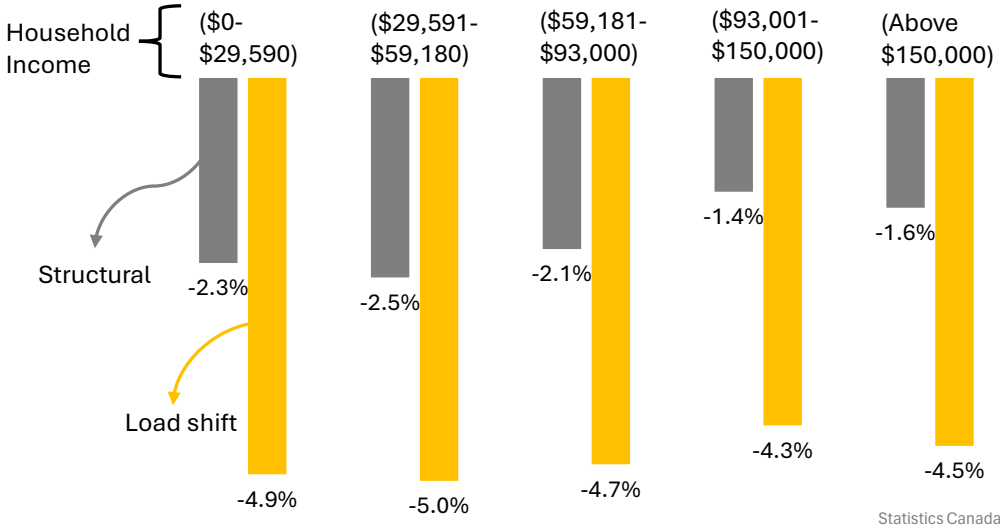
- Explore different volumetric rates and structures that increase financial savings to customers when load shifting is implemented.
- Refine modeling used to create the results presented today.
- Explore the impact to customer bill and demand with a time-differentiated demand charge TOU rate (i.e. separate peak and off-peak demand charges). Note: NS Power's current systems cannot support this as configured with current demand calculation.


Additional Income Based Investigation

RE. SYNAPSE TECHNICAL SESSION 1 COMMENTS: INCOME BASED BILLING IMPACTS

Domestic TOU Bill Impact by Household Income Levels

The domestic TOU rate reduces customer bills by 2.3% in the lowest income bracket and 1.6% in the highest income bracket; a difference of 0.7%. When load shifting is considered, the difference is reduced to 0.4%. This suggests that the TOU rate would disproportionately reduce low-income customer bills more significantly on a percentage basis.



NOTES

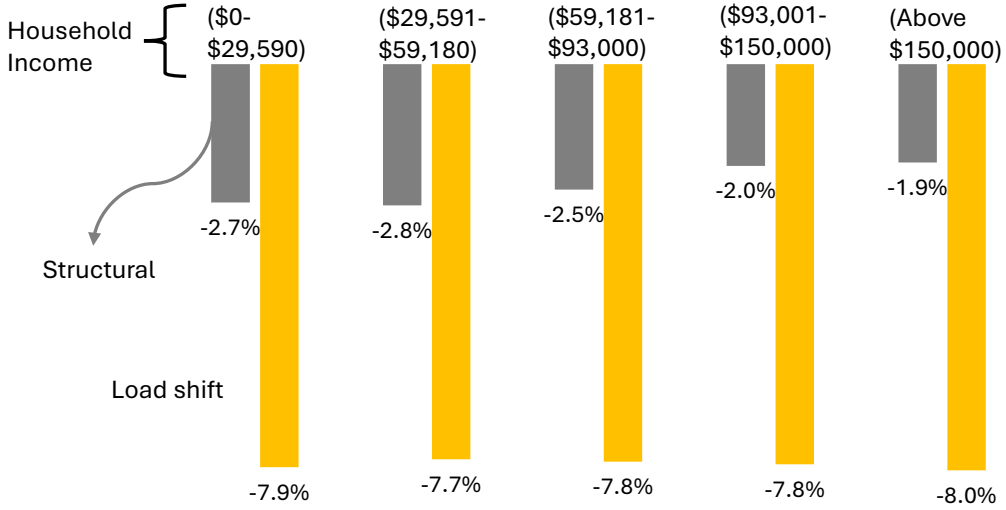
- Income is based on postal code level data from Environics Analytics. Environics Analytics uses their proprietary algorithm to disaggregate Statistics Canada income data to the 6-digit postal code level.
- This analysis uses the average load shift from the EM&V Year 3 report for all cohorts.

Sources: NS Power, AMI interval data, Jan 2024 – Dec 2024, Statistics Canada & Environics Analytics Refinement, Median Income by Postal Code, 2023

RE. SYNAPSE TECHNICAL SESSION 1 COMMENTS: INCOME BASED BILLING IMPACTS

Domestic CPP Bill Impact by Household Income Levels

The domestic CPP rate reduces customer bills by 2.7% in the lowest income bracket and 1.9% in the highest income bracket; a difference of 0.8%. When load shifting is considered, the difference is statistically insignificant. This suggests that the CPP rate would disproportionately reduce low-income customer bills without load shifting (i.e. Structural Analysis), whereas there is no difference in bill decrease between income groups when considering load shifting.



NOTES

- Income is based on postal code level data from Environics Analytics. Environics Analytics uses their proprietary algorithm to disaggregate Statistics Canada income data to the 6-digit postal code level.
- This analysis uses the average load shift from the EM&V Year 3 report for all cohorts.

Sources: NS Power, AMI interval data, Jan 2024 – Dec 2024, Statistics Canada & Environics Analytics Refinement, Median Income by Postal Code, 2023


Revisions to the Rate Design
Scorecard

Item	Objective	0 - Does Not Meet Objectives	1 - Meets Some Objectives	2 - Meets Most Objectives	3 - Meets All Objectives
Customer Orientation	The Tariff should be oriented to customers, maintaining simplicity while providing customer choices *Normalization Note* *Change from Base ≥ 10%* *a) Off-Peak: +/- 1 point* *b) Peak: +/- 1 point*	Tariff does not meet any of the 3 criteria: (1) easy to understand, (2) has attractive pricing differentials, and (3) provides customers with rate choice.	Tariff meets one of 3 criteria: (1) easy to understand, (2) has attractive pricing differentials, and (3) provides customers with rate choice.	Tariff meets two of 3 criteria: (1) easy to understand, (2) has attractive pricing differentials, and (3) provides customers with rate choice.	Tariff meets all 3 criteria: (1) easy to understand, (2) has attractive pricing differentials, and (3) provides customers with rate choice.
	The Tariff has demonstrated customer interest	<50% of Enrolment Target is met OR <10% of Customers Surveyed indicate interest	50-74.9% of Enrolment Target is OR ≥10% of Customers Surveyed indicate interest	75-99.9% of Enrolment Target is met OR ≥30% of Customers Surveyed indicate interest	100% of Enrolment Target is met OR ≥50% of Customers Surveyed indicate interest
Encourage Efficient Operations ***Informed by IRP and internal undertakings***	The Tariff should encourage system efficiency gains through load shifting potential and peak periods aligned with system peak and cost of service	<50% of peak periods are aligned with system peak	50-75% of peak periods are aligned with system peak	75-90% of peak periods are aligned with system peak	≥90% of peak periods are aligned with system peak
Fair Value	Customers load shift should be reflected in bill savings	No significant difference between customer load shift and structural savings (<1%)	Load shift customer savings exceed structural customer savings by ≥1%	Load shift customer savings exceed structural customer savings by ≥5%	Load shift customer savings exceeds structural customer savings by ≥10%
	Customers should experience annual savings compared to the standard offer rate	No annual load shift savings (<1%)	Annual load shift savings ≥1%	Annual load shift savings ≥5%	Annual load shift savings ≥10%
	Tariff volumetric rates correlate to marginal cost of electricity (i.e. largely fuel)	Volumetric rates do not reflect marginal cost of electricity. No correlation. Correlation coefficient < 0.1	Weak statistically significant correlation. Correlation coefficient ≥ 0.1	Statistically significant correlation. Correlation coefficient ≥ 0.2	Strong statistically significant correlation. Correlation coefficient ≥ 0.4
Accessibility	The Tariff should remain affordable and accessible to vulnerable sub populations	Tariff is not affordable or accessible to vulnerable sub populations	Tariff is affordable and accessible to vulnerable sub populations with many exceptions	Tariff is affordable and accessible to vulnerable sub populations with a few exceptions	Tariff is affordable and accessible to vulnerable sub populations
Customer Equality	The Tariff should aspire for a balance of 50/50 Structural Winners and Structural Losers. (Only used during rate design phase until avoided cost calculation is complete)	Under 10% are either Structural Winners or Losers	Tariff achieves balance +/- 30% (i.e. Structural Winners 20-80%)	Tariff achieves balance +/- 20% (i.e. Structural Winners 30-70%)	Tariff achieves balance +/- 10% (i.e. Structural Winners 40-60%)
	The Tariff provides customers savings equal to the avoided cost to the system when considering load shifting.	When considering all transmission, distribution, generation and fuel avoided costs, customer savings exceed system savings by more than 2%.	When considering all transmission, distribution, generation and fuel avoided costs, customer savings are not more than 2% greater than system savings.	When considering all transmission, distribution and fuel avoided costs, customer savings are not more than 2% greater than system savings.	When considering only fuel avoided costs, customer savings are not more than 2% greater than system savings.
Revenue Neutrality	The Tariff should be revenue neutral without recognition of the value of load shifting for fairness across the rate class	Structural analysis indicates average bill change greater than +/- 10%	Structural analysis indicates average bill change less than +/- 10%	Structural analysis indicates average bill change less than +/- 5%	Structural analysis indicates average bill change less than +/- 1%


4.0 – Reporting on Small Business Customer Items

Load Characteristics of Small Business Customers that may Shift Load in Response to TVP

- Reviewing load profiles for all TVP SMB customers enrolled on TVP found only the 4 customers flagged in the Year 3 Evaluation by Econoler (M11823) of the time-varying pricing pilot showed any meaningful load shift.
  - Three of these customers proved to be unique customer profiles that would not be scalable in Nova Scotia to a broader segment.
  - One customer was impacted by external factors outside of their control. Although they indicated they are aware they are on a TOU rate they have taken no direct action to shift load, and their load profile change cannot be attributed to the TOU rate.
- At this time, no characteristics of small business customers have been found that indicate a potential for load shifting outside of the MURB space.

Figure 10: Examples of Individual Load Shapes for Commercial TOU Participants



Recruitment and Customer Outreach

NS Power is currently working on the marketing and recruitment plan for the upcoming year. For Commercial and Business customers, we plan to enhance the strategic approach to get in front of the decision makers through the channel that resonates with them.

- **What we've learned:**
  - The Commercial and Business customer journey requires a personalized approach with a longer timeline from to make the decision (more than 2 months).
  - There can be more than one decision maker, who value face-to-face conversations and appreciate seeing the cost savings.
- **What we are proposing:**
  - Leverage NS Power Commercial Advisors – as they are the trusted partners, who know the correct decision makers.
  - Allowing NS Power Commercial Advisors to begin conversations now and build out application information that can sometime take longer to collect then the regular recruitment season.
  - Target larger commercial customers with a profile of accounts who would achieve better value in TVP Rates this could be universities, retail chains, etc.
  - Work with more associations to look at hosting webinars, presentations or publish detailed articles.
  - Continue with awareness efforts to such as Google Search and other channels, retargeting customers we are engaging with.

Customer Hesitations and Potential Solutions

- Sample of responses from discussions with customers:
  - Potential savings, even for structural winners often felt to be not enough to be worth the effort.
  - Skepticism that energy shifting is possible in their business without technology and capital investment.
  - Potential higher bills in winter months, even with total annual savings is still a negative variance explanation some business leaders would need to justify on their performance metrics.
- Potential Changes that could can address some of the concerns:
  - Revise the TOU rate structure to target increased savings for customers who do shift 4%-6% of load in line as discussed in the prior load shift model.
  - Reduce the seasonal effect of the rate to minimize the impact of higher winter bill relative to the standard offer rate.
  - Explore technology options for customers that may allow the load shifting to be automated.


4.0 (continued)
Commercial Segmentation
LOCAL SHOPS
LOCAL BUSINESS
SMALL MEDIUM BUSTNESSS


What We Knew About Customers Before

Commercial Rates

Educational institutions, businesses, retail stores, office buildings









Rate 10/72/82 – small commercial

- Annual consumption is less than 32,000 kWh (or, at customer option, less than 45,000 kWh per year)
- Small retail, corner stores, strip mall offices, dental offices

~26K

Rate 11/73/83 – commercial

- Annual consumption is 32,000 kWh or greater and the regular billing demand is less than 2,000 kVA or 1,800 kW
- Hotels, shopping malls/plazas, office buildings

~11K

Rate 12 - Large commercial

- Consumption for any use except industrial, where the regular billing demand is 2,000 kVA or 1,800 kW, and over
- Hospitals and large retail malls– average monthly bill >$100,000 per month

20 Customers

Source: DB2 Active customer counts as of August 17, 2023


What We Know About Customers Now

Key Features of Commercial Segmentation Model



Customer Profiling

Gaining deeper insights into customer-specific information, including PID, CAID, CID, rate code, meter ID, address, and account status.

Data source: AMI Data + Feature Engineering



Vertical Segmentation

Classifying businesses into 29 distinct verticals, to accurately identify their respective industry segments.

Data source: CIS + ML Model



Standardized Business Names

Consolidating variations of account names (eg: H.C.C.C and HCCC) into a unified format (like Halifax Co Condo Corp) for consistency and accurate analysis.

Data source: CIS + ML Model



Power Factor Insights

Calculates Average, Min, and Max Power Factor, helping identify customers with low efficiency for potential power factor correction.

Data source: CIS+ AMI+ Feature Engineering



Annual Billed Metrics

Calculated fields for Annual Billed Consumption, Peak Demand, and Revenue. This enables accurate insights into energy usage, demand peaks, and revenue, which are essential for financial forecasting and identifying high-value customers.

Data source: CIS+ AMI+ Feature Engineering



Geographic & Work Zone segments

Geographic and work zone-based segmentation divides customers by specific work zones (e.g., DAR, BAY, BRT), enabling a more localized analysis of energy usage.

Data source: CIS+ AMI



Service & Connection Insights

Service and connection insights provide data on initial service dates, connection dates, and status codes (e.g., Active/Closed).

Data source: CIS+ AMI



Interval Data & AMI Meter Status

Interval data and AMI status monitoring track total interval counts, compare actual vs. estimated read percentages, and provide information on whether a meter is a full-year, mid-year, or late-year installation.

Data source: CIS+ AMI+Feature Engineering

Standardized Commercial Names

BANK OF MONTREAL #089
BANK OF MONTREAL BM00133
BANK OF MONTREAL TRANSIT
2159
BANK OF MONTREAL #0208
BANK OF MONTREAL
BM00145
BANK OF MONTREAL BM00133
Bank of Montreal #0206
BANK OF MONTREAL BM03985
BANK OF MONTREAL BM00133
BANK OF MONTREAL #0182

Standardization

BANK OF MONTREAL



CIS Database

Approaches:
- Trimming spaces.
- Normalizing Case
- Removing extra Characters
- ~40K CAID to 20K Standardized Names



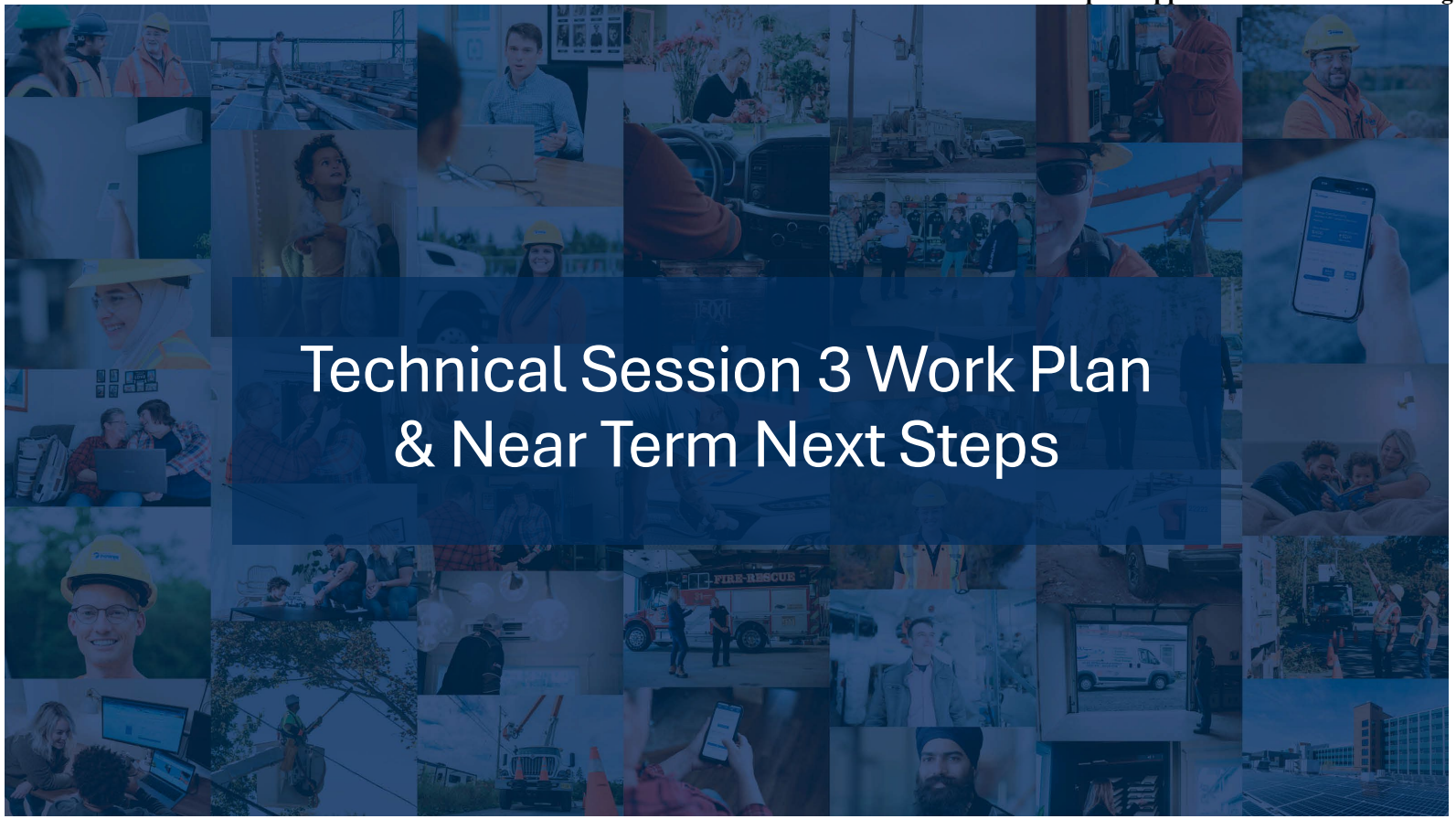
Standardized Name in Segmentation Model

Verticals in Commercial Segmentation Model



Commentary :

- ML Model is used.
- **~364 distinct keywords** were used.
- Supervised Learning Method.
- **Random Forest Classifier – Predictive Analytics**
- Tfid Vectorizer.
- **Model Accuracy ~92%.**
- C & I ~40k Accounts into **Mutually Exclusive & Collectively Exhaustive verticals.**


Technical Session 3 Work Plan
& Near Term Next Steps
FIRE-RESCUE

2024/25 Areas of Focus – Revised Work Plan (1/2)

Technical Session 3 – anticipated week of 12 May (tbc)

Summary of 2024/25 Areas of Focus & Board Directives	Type	Items to be Discussed/Reviewed
5.0 – Potential Tariff Changes / Introductions • (5.1) identify potential tariff changes which could improve customer participation in the TVP program, load shifting and alignment with the highest cost hours	BD	• Examine customers' correlation with system peaks by rate class • Discuss the tradeoffs with a seasonally neutral TVP rate relative to the standard rate to allow year-round enrolment. This could remove a barrier to higher participation at the trade of off a potentially lower correlation to system costs. • **NEW** – in response to Synapse's comments, in the TVP 2024/25 Kick-off Session in November 2024, on what a potential structure for a seasonally adjusted default rate might look like. NS Power will provide a reference rate with only a seasonal adjustment. NS Power does not intend to pursue such a rate other then as an informational tool on seasonal impacts for stakeholders. • Undertake development and assessment of a rate including both Saturday and/or Sunday on the targeted rate class and the impact on potential TOU rates and the broader TVP development strategy • Review the opportunities and restrictions with batteries today on current TVP rates and general demand rates when paired with consumption and develop recommendations to address, as appropriate. • Identify and evaluate additional potential use cases of behind-the-meter energy storage in the context of TVP pricing ratios (e.g. 2:1, 10:1) and net metering.
• (5.2) Board directive from SGNS Final Report (M11621) – discussion of new and/or revised tariffs enabling customers to have the option to charge from, and discharge to, the grid with behind-the-meter energy storage (including vehicle-to-grid) that is not integrated with generation	BD	
• (5.3) examination of alternative Domestic tariffs including a TOU structure with weekend peak/off-peak periods	CA	
• (5.4) provide a draft weekend-inclusive TOU tariff to be reviewed by stakeholders in the upcoming engagement sessions	BD	

2024/25 Areas of Focus – Revised Work Plan (2/2)

Technical Session 3 – anticipated week of 12 May (tbc)

Summary of 2024/25 Areas of Focus & Board Directives	Type	Items to be Discussed/Reviewed
6.0 – Review of System Planning Related Values • (6.1) review of system planning related values as applicable to TVP (and the technologies that deliver the load shifting such as batteries) including avoided costs and Effective Load Carrying Capability (ELCC)	CA	Review system planning related value applicable to TVP including: • Technologies that deliver load shifting • Update on the avoided cost analysis from 2023/24 (Year Three) Technical Sessions, how the avoided costs were applied to TVP, and rate design scorecard to discuss the assessment of TVP cost reflectivity • Examine alignment of TVP pricing with avoided cost and determine implications for future TVP pricing • Review of ELCC as applied to TVP • Review and establish the parameters for the analysis of system margin and CPP events to be provided in the Year 4 Report • NEW – in response to the Energy Storage Canada comments, NS Power will: o Discuss why NS Power still views the winter evening peak to be the most likely and impactful time for a system peak moving forward. Variability in weather systems can affect timing of system peaks. This creates the potential for system peak to occur at other times such as the morning or weekend daily peaks. o What role TVP can play in meeting load and reserve requirements. Both though demand side flexibility, as well as by reducing variability in daily load.
• (6.2) discuss an assessment of the degree to which the TVP offering reflects avoided costs, with the potential for modifications to the tariffs to ensure that they are cost-reflective	BD	
• (6.3) discuss an analysis of the correspondence of system margin forecasts and CPP events in the Year 4 report, providing the days with a forecast of low system margin and the forecast system margin for the days when a CPP event was called	BD	



Near Term Next Steps

- Fri, 4 Apr – NS Power circulated slides
- Today (Mon, 7 Apr) – Technical Session 2
- Fri, 18 Apr – stakeholders provide comments on this deck, including the Work Plan for the upcoming Technical Session 3, to NS Power
- Anticipated week of 12 May (tbc) – NS Power schedule Technical Session 3

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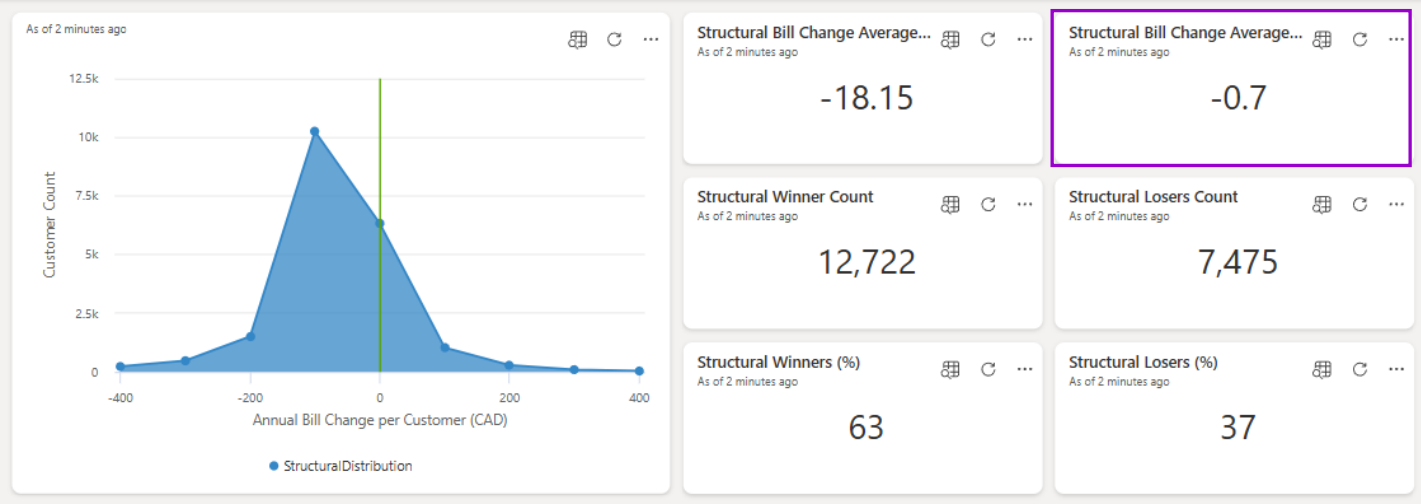

Appendix

RE. SYNAPSE TECHNICAL SESSION 1 COMMENTS (ITEM 2)

Small General, CPP (15 events, +3 hypothetical)

Model Commentary

- CPP volumetric rates effective November 1, 2024
- Includes 2025 riders
- AMI data domain: January 1 – December 31, 2024 inclusive
- Structural bill change = -0.7 % - Note that a structural bill change of -2.0% was modeled with 15 events and presented in technical session 1 on March 3rd, 2025.

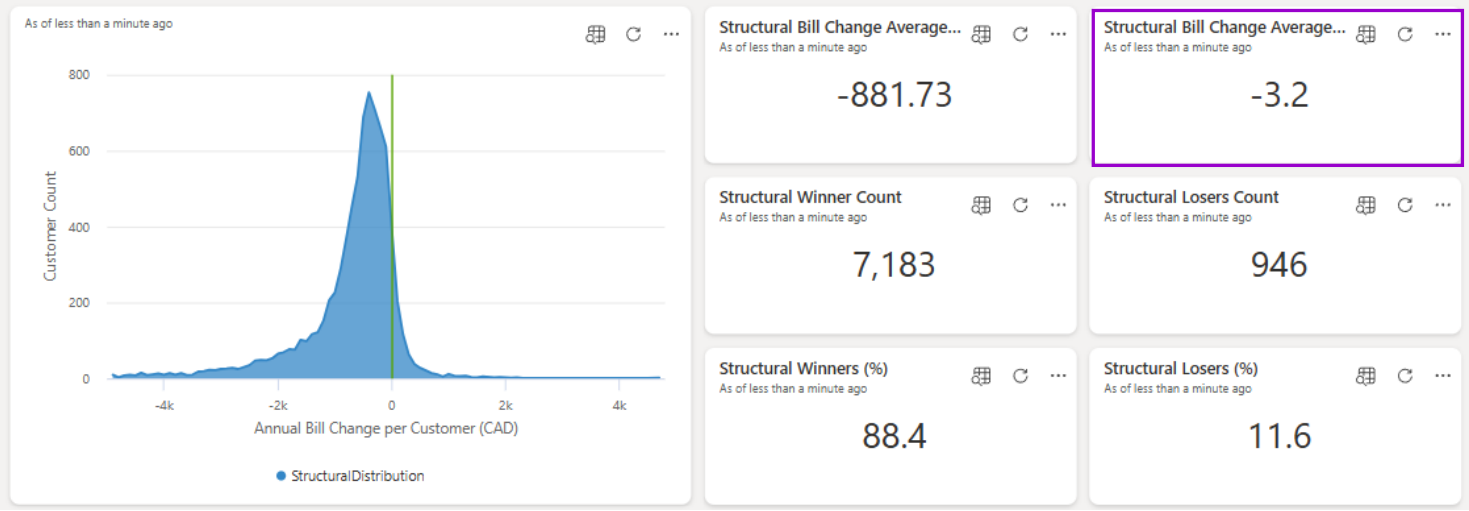


RE. SYNAPSE TECHNICAL SESSION 1 COMMENTS (ITEM 2)

General, CPP (15 events, +3 hypothetical)

Model Commentary

- CPP volumetric rates effective November 1, 2024
- Includes 2025 riders
- AMI data domain: January 1 – December 31, 2024 inclusive
- Structural bill change = -3.2 % - Note that a structural bill change of -4.7% was modeled with 15 events and presented in technical session 1 on March 3rd, 2025.



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TIME-VARYING PRICING TARIFF PROGRAM
NS POWER RESPONSES TO STAKEHOLDER COMMENTS

TVP Session	Technical Session 1 – held 3 March 2025
Comments Received	14 March 2025
Responses Circulated	4 April 2025

Stakeholder	Comment	NS Power Response
Consumer Advocate (CA)	*Comments regarding the Accessibility of TVP* On December 12th, 2024, the Consumer Advocate provided comments regarding NSP's draft 2024/2025 Areas of Focus Work Plan and the proposed list of MURB TOU Tariff evaluation metrics. Some of these comments focused on the accessibility of the TVP to persons who live in rental accommodation. For ease of reference, the comments regarding accessibility are repeated below: The Consumer Advocate questions whether renters may face greater barriers to participation in the TVP than homeowners as they may have less control over their heating sources, appliances, and electricity use. Has NSP considered whether renters face more barriers than homeowners do in accessing TVP? If so, does NSP have a plan to address the barriers renters face in accessing this program? NSP responded to these comments in its January 30, 2025 materials provided in advance of Technical Session 1. To paraphrase the response received to these questions, NSP stated: • There are no restrictions on renters joining the TVP, • The TVP rates do not require a change in heating sources to be successful, • Survey data from participants in the TVP which showed the most common type of change participants made was behavioral, • While only 6% of year 3 applicants for enrollment in the TVP identified as living in an apartment, 12% of year 4 applicants identified as living in an apartment.	NS Power appreciates this suggestion will conduct an updated survey of existing TVP participants this spring. As Narrative noted in the Year Three Survey Results[1], it was a challenge in assigning a high level of confidence to the results in the smallest income bracket due to the small sample size. This limited further segmenting other survey questions by income from the current survey data. Higher enrollment by customers that met the low-income threshold in Year 4 may result in a greater ability to segment survey responses by income-level in the refreshed (Year 4) TVP survey results[2]. As has been the practice in past reports, NS Power will share the results of its Year 4 participant survey and will continue to share learnings with stakeholders as part of the ongoing pricing innovation and engagement process.

[1] M11823 – NS Power, Year Three TVP Evaluation Report, Appendix C, page 14 of 65. July 31, 2024.
[2] As reported in Technical Session 1, slide 39, of the residential applicants that self-reported their income levels as part of their TVP Tariff Year 4 application, approximately 11% met the Statistics Canada low-income cut-off (LICO) threshold.

Stakeholder	Comment	NS Power Response
	While the Consumer Advocate appreciates receiving a response from NSP to these concerns, the Consumer Advocate remains concerned renters may face barriers to participating in the TVP which could potentially be better understood and addressed. During Technical Session 1, Melissa Whited on behalf of UARB Counsel noted that the data provided by NSP indicates that low-income participants in the TVP have a lower satisfaction rate with the program than do higher-income participants. Ms. Whited noted that NSP currently lacks information about why satisfaction rates with TVP differ by income. She suggested that to learn further information about satisfaction rates by income level, a survey of participants could be designed. This survey could provide helpful information about how to improve satisfaction rates with the TVP for low-income participants. She noted that an example of what the survey could reveal is a lack of access to a particular tool, such as a smart thermostat, which could improve low-income participants' satisfaction with the TVP. The Consumer Advocate echoes Ms. Whited's suggestion that NSP conduct research regarding why satisfaction rates with the TVP appear to differ by income level. Results from this research may reveal whether renters face barriers to participating in the TVP. This research could also indicate whether these barriers can be eliminated.	
Energy Storage Canada (ESC)	With regard to 2.4 "review of current metering and billing system capabilities", the current capabilities are a barrier/disincentive to efficient price signals and optimized operation of bi-directional demand-side measures (e.g., battery storage, vehicle to grid). Net metering on time-varying rates would maximize energy arbitrage potential (i.e., price signal currently limited to load displacement, not extended to export). Time varying demand charges would maximize the incentive to charge off-peak (i.e., peak set during on-peak and off-peak times are currently treated similarly). A feedback loop between NSPI's "DER Integration Roadmap" initiative and the TVP process would be appreciated to ensure alignment on the evolving topics of rate design and time-varying price signals for bi-directional demand-side measures (e.g., battery storage, vehicle to grid).	The Board's Decision on the Smart Grid Nova Scotia Final Report provided direction regarding the scope of the Distributed Energy Resource (DER) Integration Roadmap: "[...] the Board anticipates that the development of a DER Integration Roadmap will also consider potential rate design issues and programs, both in respect of initiatives that may be planned by the utility and in anticipation of the need to respond to expected customer-driven activity in this area.[3]" Accordingly, NS Power anticipates that the rates items noted by Energy Storage Canada will be included for consideration in the DER Integration Roadmap work and associated stakeholder engagement. The recommended feedback loop between the TVP process and the DER Integration Roadmap is well received. Those discussions are underway within the Company to coordinate initiatives and work though challenges such as those highlighted in ESC's comment.

[3] M11621 – NSUARB Decision, 316523, page 8. October 28, 2024.

Stakeholder	Comment	NS Power Response
Energy Storage Canada (ESC)	Will the Avoided Cost from TVP and DSM reflect the results from the new Line Loss Study? Do the results from the new Line Loss Study represent any material changes from prior assumptions as it relates to the value of peak-shifting for various customer classes?	NS Power does not intend on updating the Avoided Cost study with the changes from the new line loss study. When compared to previous assumptions, residential losses have decreased and business, non-profit, and institutional (BNI) losses have increased. As a result the impacts will be offsetting and only minor impacts on the avoided cost results would be expected. The results from the most recent line loss study will be used as part of the refreshed TVP analysis.
Small Business Advocate (SBA)	**Slide 38: Summary of Business Recruitment Key Contacts** 1. Please explain why there are zero TOU Applications received but 54 TOU Pilot Enrollments? 2. Does that mean a small business is enrolled in the Pilot but has not submitted an application? If yes, how does that occur? 3. Please confirm whether any of the small businesses in the Enrolment Target group, the Application group and the Pilot Enrolment group are also considered MURB customers. 4. There are three Highlights listed: email opens/clicks; click through rate (CTR) and non-digital tactics. Please explain the significance of the actions highlighted and why these 3 areas were specifically deemed to be noteworthy. 5. Please provide the formula for click rate, i.e., what is the numerator and the denominator? 6. Please explain why the number of applications for Year 4 declined to zero after being positive for Years 1, 2, and 3? 7. Regarding footnote (*) if zero TOU applications were received, does this mean that the one application received for multiple SMB accounts was for the CPP rate only? 8. What does NS Power think are the reasons that there was a decline in interest in the TOU program, as evidenced by it receiving zero applications, in Year 4?	1. NS Power has had 54 TOU small-medium business (SMB) enrollments in total (i.e. since Year 1). 2. No, please refer to response above. Also note that, some customers with multiple accounts only need to submit one application; therefore, it is possible for there to be more enrolments than applications. 3. Currently SMB and multi-unit residential buildings (MURB) are tracked separately. Tracking them independently is beneficial to measure the effectiveness of each TVP Tariff. When measuring the response of classes rates to TVP in general there may be situations in the future where MURBs may be grouped within the General rate class, as MURBs are a subgroup of the General class. 4. The marketing metrics list the key data points that highlight the performance of different tactics. a. Email opens/clicks highlight the email recipient's engagement and interaction with the communications. NS Power calls out the 'opens' as it shows how effective the email/message was in getting recipients to open and review content. The clicks show that not only did these recipients open the email, but they were interested enough to click one of the many links or Call to Actions within the email. b. Click through rate (CTR) is a primary metric to relative to paid digital advertising. It measures the percentage of clicks an advertisement receives. 5. Including the non-digital tactics allows NS Power to see holistically, how the campaign performed. It is also important to note that many non-digital efforts included push to NS Power's landing pages and with the use of Urchin Tracking Module UTM) Tracking, NS Power was able to quantify and see this traffic. The formula for click rate is the total clicks from an email divided by the number of emails delivered and multiplied by 100. This percentage tells you how many successfully delivered campaigns registered at least one click. Note: this is per email and then averaged for the

Stakeholder	Comment	NS Power Response
		complete campaign. For example, an email had 1,143 clicks and 9,862 successfully delivered emails, multiply by 100 equals a click rate of 12%. 6. NS Power understands this question to be in reference to TOU SMB enrollment, in which case, SMB customers opted for CPP more than TOU when presented both rates. This resulted in 0 TOU applications and 26 CPP applications. 7. Yes, NS Power had a couple of SMB customers who applied with one application but signed up multiple accounts for the CPP Tariff. The Application Processing team worked with the Customer and Commercial Advisor to ensure all accounts that were eligible/interested were enrolled. 8. Based on discussions with NS Power's Commercial Advisors, who directly interact with potential customers, SMB customers were less inclined to enroll in TOU due to the nature of their business – for instance, finding it difficult to accommodate energy changes during the peak periods for an entire winter period. Additionally, when breaking down the cost savings by analyzing historic energy usage, CPP appeared to be more achievable with greater potential savings for those customers.
Small Business Advocate (SBA)	**Slide 40: SMB Recruitment:** We have assumed that SMB refers to Small Business, but please confirm. 1. Is NS Power able to increase enrolment in the TOU an/or CPP programs beyond the current enrolment, as of March 4, 2025, and have it still be counted in Year 4 results and evaluations? 2. If so, how does NS Power plan to achieve an increased enrolment and what is the timing for this plan? 3. Please explain what the statement "Commercial Advisors leveraged the TVP rates in customer conversations" means and how did it help if there were zero TOU applications received? 4. If 31% of pilot participants identified that they heat electrically, which is a 34% decrease from the number of pilot participants who identified that they heat electrically last year, is the decrease reflective of there being an increase in the number of and this the pool of (CPP) applicants rather than a reduction in the number of customers using electricity?	Confirmed, SMB stands for Small-to-Medium Business. 1. No, enrolment in all TVP Tariffs for Year Four closed on December 31, 2025. Tariff recruitment and enrolment occurs on an annual cycle and closes by the end of the calendar year of the TVP season to: (a) reduce the potential for customers to arbitrage the rate by joining at or near the end of the TVP winter season, and (b) to ensure consistency of the treatment group for evaluation, measurement, and verification (EM&V) purposes. 2. Please see response above. 3. Although there were no TOU applications for SMB, NS Power's Commercial Advisors approached and discussed TVP Tariffs with customers who had not heard of the Program. Although these customers were presented with information on both TVP offerings, the Year 4 applicants were more interested in CPP over TOU. 4. The 31% of customers are those who applied in the most recent Year 4 enrolment period, rather than 31% of all enrolled customers. The decline in electrically heated customers (from 44% in Year 3 to 31% in Year 4) is relative to those who applied in the respective enrolment periods. 5. Despite not seeing large enrollment numbers, the Company gained more insights from customers through conversations. With this, NS Power determined that approach for SMB

Stakeholder	Comment	NS Power Response
	5. How does NS Power plan to capitalize on what it learned from the limited success of its "customized recruitment approach" when it uses it again in year 5? Will more resources be required to do this?	cannot be the same as residential. To elaborate, what is most successful for residential (email) is not as successful for SMB. This is because the email lists available do not necessarily go to the decision makers in the business. What was most successful was face-to-face conversations. NS Power is may consider investing in presentations, tradeshows, and have trusted advisors approach identified customers. The scale of the resources required due to the high cost of acquisition for SMB customer joining a TVP rate will limit the effort invested into recruiting SMB in the following year.
Small Business Advocate (SBA)	**Slide 42: Year 4 – Challenges and Opportunities:** 1. Channels & Timing: The Opportunities include needing longer lead times and recruitment periods. Please explain how the delay in starting recruitment for Year 4 will be avoided for Year 5? 2. Channels & Timing: What plans does NS Power have to add more marketing channels and touchpoints with customers? 3. Does the delayed start in the recruitment period combined with the low percentage of target achieved mean that the results of the TOU and CPP marketing effectiveness analysis will not be statistically significant, as it has been for prior years?	1. NS Power does not begin recruitment for an upcoming TVP season until it has received Board-approval of its proposed TVP Tariff offerings. Last year, the Company applied for 2024/25 TVP Tariffs on July 31. This year, and coming years, it aims to make its coming TVP season application before July 31, to allow more time following a Board Decision for recruitment and onboarding. 2. NS Power is currently working on the Year 5 marketing and recruitment plan and, subject to budgets and resources, may add new channels. 3. The statistically significant issues for SMB regarding low enrolment do not apply the same way to the effectiveness of marketing and enrollment metrics as they do for EM&V. The continued low enrolment and minimal response (see figures 11-13 and 15-17 from Appendix A of the Year Three Report, M11823) for SMB will likely result in Year 4 load impact results being statistically insignificant. Increasing the sample size may yield statistically significant results, however there is no evidence to support that statistical significance will result purely from increased sample size.
Small Business Advocate (SBA)	**Slide 50: Email:** NS Power found that small business customers were more engaged (e.g., had higher click through rates) with email marketing efforts but also found that the conversations with customers (Slide 40) and Chamber of Commerce events (Slide 56), which presumably provided opportunities to meet customers face to face, were very effective. 1. How does NS Power plan to allocate its resources to obtain better results for Year 4 evaluation with these two approaches, i.e., are there enough resources to do both email marketing as well as conversations with customers and Chamber of	1. In Year 4, NS Power was able to test different channels and approaches for SMB recruitment which proved there is opportunity to test this out on a larger scale. Year 5 marketing and recruitment planning has begun, and NS Power is looking at the various tactics and options we may implement, and what resources and budgets those will require. Please also refer to responses to slide 40.

Nova Scotia POWER An Emera Company

TIME-VARYING PRICING TARIFF PROGRAM

NS POWER RESPONSES TO STAKEHOLDER COMMENTS

Stakeholder	Comment	NS Power Response
	Commerce type events or will there be trade-offs due to budget constraints and the lead time required?	
Small Business Advocate (SBA)	**Slide 56: SMB Engagement:** 1. In the images shown on this slide, there is a notice at the bottom about a Small Business Week event (not NS Power branded). Does this belong with the Yarmouth or Cape Breton newsletter? Are there other locations in Nova Scotia that sponsor similar events and does NS Power have a plan to participate in these events? If so, what is the timeline for this plan? 2. Did the banner ad shown, whether for Yarmouth or Cape Breton, for the Time Varying Pricing Rate Pilot Program, result in any pilot participants from either Yarmouth or Cape Breton? 3. Are there other Chamber of Commerce organizations that NS Power can work with or do these two (Yarmouth and Cape Breton) have a broader reach across Nova Scotia? 4. Does someone from NS Power attend regular Chamber of Commerce meetings? 5. Are there other opportunities for NS Power to present to a targeted audience that have a common interest in serving small businesses, for example as it did with the Association of Energy Engineers? How does NS Power plan to follow up on the conversations that it had with the commercial building energy designers at the Association of Energy Engineers conference?	1. In reference to the Small Business Week ad, this was from the Yarmouth Newsletter (from the link provided on slide 56). The image displayed on slide 53 that is not NS Power branded is a social media promotional post for an event/conference in which NS Power Subject Matter Experts presented on TVP. As previously mentioned, NS Power is currently working on its Year 5 marketing and recruitment plan, which will identify events / opportunities for 2025/26. The timeline is not yet finalized. 2. NS Power was not able to track enrolment by these specific tactics/outreach. To track in future, we will be adding a "How did you find us" question to the application. 3. For Year 4, the Company reached out to all the Chambers in Nova Scotia. However, Yarmouth and Cape Breton were the only two that could accommodate. NS Power is looking to do more with all Chambers in Year 5. 4. Various NS Power staff attend chamber events. The Marketing team has set up regular touch points with their staff to stay up to date on opportunities. 5. Yes, NS Power is always looking to participate in relevant events where exposure and information about TVP is directly relevant to the attendees. Follow up conversations from these events is a continual and cumulative part of building relationships with potential participants. Should stakeholders be involved in organizing events they feel would benefit from our involvement, the Company would be happy to discuss those opportunities.
Board Counsel Consultant, Synapse Energy Economics (Synapse, BCC)	**1. Accessibility of TVP Tariffs** Synapse remains concerned regarding lower-income participation and ability to respond. With respect to enrollment, the data available suggest that the TVP tariffs do not appeal as much to lower-income customers and customers in apartments. In particular:	With respect to the statements made by Synapse relating to income satisfaction. NS Power Is cautious to draw any conclusion that satisfaction, or enrolment differentials that may be seen in the data noted are statically meaningful giving the data quality restrictions regarding income level data available as discussed in Technical Session 1 or comparing data between sources with different methodologies. NS Power has added a breakdown of savings by both TOU and CPP rates segmented by provincial income level data in technical session two. Although this data will have the same restriction on the interpretation of income level stemming from postal code level data and potential to increase the statistical error found in load shifting results, they are helpful to understand how customers at varying incomes are being impacted by each rate.

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<tr><th>Stakeholder</th><th>Comment</th><th>NS Power Response</th></tr>
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The results of customer surveys show that interest in time-variable pricing “increases with household income,” and “is lowest among customers who live in a condo/apartment.”[4]
Low income customers (<$30,000) were nearly twice as likely to be dissatisfied with the TOU pilot relative to the highest income bracket ($100,000+).[5]
The majority (54%) of respondents to Narrative Research’s 2021 survey were higher-income households.[6] If survey respondents are reflective of the total population of TVP participants, this indicates that lower-income households are less likely to enroll in TVP.
NS Power reports that 12% of Year 4 applications were from customers identifying as living in an apartment.[7] Yet Statistics Canada reports that 25.5% of Nova Scotia’s housing stock is apartments.[8] Although 12% is an increase from the 6% enrollment rate in Year 3, it is still well below proportional representation.

The lower levels of interest and enrollment lead to the following questions:

Are lower-income customers and apartment dwellers proportionately less likely to enroll in TVP Tariffs?
Do lower-income customers and apartment dwellers tend to favor one form of TVP over another?
Assuming lower participation levels, why are lower-income customers and apartment dwellers less likely to enroll in TVP tariffs? (E.g., less available load to

</td><td>
Should improving data quality with higher enrollment numbers show participation levels among distinct income class be identified as a significant variance from average enrolment, that may present an opportunity for more focused marketing and awareness in future campaigns.

Please see the enrolment application information for reported household income for all applicants since the start of the pilot.

<table>
<tr><th rowspan="2">Income</th><th colspan="2">Count of</th><th colspan="2">% of</th></tr>
<tr><th>CPP</th><th>TOU</th><th>CPP</th><th>TOU</th></tr>
<tr><td><$19,999</td><td>110</td><td>232</td><td>4%</td><td>4%</td></tr>
<tr><td>$20,000 to $29,000</td><td>169</td><td>370</td><td>6%</td><td>6%</td></tr>
<tr><td>$30,000 to $39,999</td><td>195</td><td>477</td><td>7%</td><td>7%</td></tr>
<tr><td>$40,000 to $49,999</td><td>204</td><td>556</td><td>7%</td><td>9%</td></tr>
<tr><td>$50,000 to $59,999</td><td>231</td><td>574</td><td>8%</td><td>9%</td></tr>
<tr><td>$60,000 to $74,999</td><td>355</td><td>831</td><td>12%</td><td>13%</td></tr>
<tr><td>$75,000 to $99,999</td><td>421</td><td>903</td><td>15%</td><td>14%</td></tr>
<tr><td>$100,000 to $149,999</td><td>415</td><td>788</td><td>14%</td><td>12%</td></tr>
<tr><td>$150,000+</td><td>227</td><td>429</td><td>8%</td><td>7%</td></tr>
<tr><td>Prefer not to say/Blank</td><td>559</td><td>1,261</td><td>19%</td><td>20%</td></tr>
<tr><td>Grand Total</td><td>2,886</td><td>6,421</td><td>100%</td><td>100%</td></tr>
</table>
<ol start="2">
Please see the enrolment application information for housing by rate. House information collected after Year 2 changed options for customers to during enrolment.

</td></tr>
</table>

[4] Narrative Research, Nova Scotia Power Time Variable Pricing Report: Residential Overall. June 2021. Provided as 2022 TVP Interim Report SBA IR-4 Attachment 2 Page 32 of 53, and as an attachment to NS Power’s “2024/25 Areas of Focus Revised Work Plan.” January 30, 2025.
[5] TVP Pilot Program 2023/24 (Year Three) Evaluation Report, Appendix B, p. 14 of 65.
[6] 54% of survey respondents reported having household incomes higher than $80,000, which is above the median household income of approximately $72,000. Government of Nova Scotia, Economics and Statistics Division, “Census Income, 2021.” July 13, 2022. Available at https://novascotia.ca/finance/statistics/archive_news.asp?id=17976.
[7] NS Power Responses to Stakeholder Comments. January 30, 2025.
[8] There are 117.1 apartments per 1,000 residents out of 459 housing units per 1,000 residents, which equates to 25.5%. Government of Nova Scotia, Economics and Statistics Division, “Housing Stock, Q4 2024.” February 28, 2025. Available at https://novascotia.ca/finance/statistics/archive_news.asp?id=20776&dg=&df=&dto=0&dti=3

<table>
<tr><th>Stakeholder</th><th>Comment</th><th>NS Power Response</th></tr>
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shift, less control over heating/cooling, fewer timers or other programmable technologies, more household members home during on-peak hours, etc.)

To inform this discussion, Synapse requests that NS Power provide the stakeholder group with the following data:
1. Total number of customers currently enrolled in each domestic TVP tariff, segmented by reported household income (e.g., in $10,000 increments).
2. Total number of customers currently enrolled in each domestic TVP tariff by reported housing type (e.g., apartment, house, etc.)
3. If known, dominant forms of load shifting by housing type or income.

In terms of customer load response, the results from the Year 3 Report indicate that customers with lower incomes respond less than higher-income households. However, the results are not statistically significant, which makes it difficult to understand whether lower-income households are less likely to save money on TVP tariffs.

Synapse continues to recommend that more granular income data be used to study whether lower-income households truly shift less load than higher-income households. Synapse understands that there may be concerns regarding greater statistical segmentation by income due to the difficulty of knowing the income levels for control group customers and already large error bars. However, we submit that measuring load response by segmenting customers into only two groups may mask important differences. If the middle third of participants (with incomes of approximately $50,000–$100,000) is relatively homogenous in behavior, lumping them in with either extreme (as in a median split) can dilute the differences between low and high incomes. Therefore, Synapse recommends that NS Power segment domestic TVP participants into tertiles (thirds) to determine how lower-income customers respond relative to the highest income participants. By isolating the extremes, the data may reveal clearer contrasts in responses, to the extent where the effect size can be so large between the extremes that it overcomes the reduced sample size and larger variance.
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Participants who Enrolled in Years 3 & 4
<table>
<tr><th rowspan="2">Housing</th><th colspan="2">Count of</th><th colspan="2">% of</th></tr>
<tr><th>CPP</th><th>TOU</th><th>CPP</th><th>TOU</th></tr>
<tr><td>Apartment/Condo</td><td>42</td><td>93</td><td>14%</td><td>11%</td></tr>
<tr><td>Singe family/detached >=1986</td><td>204</td><td>566</td><td>69%</td><td>70%</td></tr>
<tr><td>Single family detached <1986</td><td>17</td><td>37</td><td>6%</td><td>5%</td></tr>
<tr><td>(blank)</td><td>33</td><td>117</td><td>11%</td><td>14%</td></tr>
<tr><td>Grand Total</td><td>296</td><td>813</td><td>100%</td><td>100%</td></tr>
</table>
Participants who Enrolled in Years 3 & 4
<table>
<tr><th rowspan="2">Housing</th><th colspan="2">Count of</th><th colspan="2">% of</th></tr>
<tr><th>CPP</th><th>TOU</th><th>CPP</th><th>TOU</th></tr>
<tr><td>Apartment</td><td>297</td><td>619</td><td>11%</td><td>11%</td></tr>
<tr><td>Condo</td><td>55</td><td>145</td><td>2%</td><td>3%</td></tr>
<tr><td>Duplex</td><td>203</td><td>374</td><td>8%</td><td>6%</td></tr>
<tr><td>Mobile home</td><td>103</td><td>226</td><td>4%</td><td>4%</td></tr>
<tr><td>Single family/detached</td><td>1,798</td><td>4,023</td><td>69%</td><td>70%</td></tr>
<tr><td>Townhouse</td><td>100</td><td>192</td><td>4%</td><td>3%</td></tr>
<tr><td>(blank)</td><td>56</td><td>207</td><td>2%</td><td>4%</td></tr>
<tr><td>Grand Total</td><td>2,612</td><td>5,786</td><td>100%</td><td>100%</td></tr>
</table>
3. This is not known. NS Power is actively looking to determine forms of load shifting based on heating type though the heating type segmentation that was added to the EM&V in the most recent report with potential refinements. As that methodology is refined, segmenting the results by other demographic information as it is available may provide additional information into the forms of heating load shifting occurring by demographic.

Nova Scotia Power agrees that the income grouping currently used could obscure differences in the tails of the income distribution. Nova Scotia Power agrees that with increasing participation it is a reasonable time to explore splitting the income into thirds in the Year 4 EM&V report as a balanced approach.
</td></tr>
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Stakeholder	Comment	NS Power Response
Board Counsel Consultant, Synapse Energy Economics (Synapse, BCC)	**2. Review of Current Tariffs** Revenue Neutrality: Synapse appreciates NS Power providing the average structural bill change for the Domestic CPP tariff under a hypothetical scenario in which 18 events are called. **We request that NS Power also provide the average structural bill change for the Small General and General CPP tariffs assuming 18 events** to understand the extent to which the rates are revenue neutral. Multi-Unit Residential Building (MURB) Tariff: In the stakeholder session, it was noted that the MURB rate applies only to the house meter, rather than to the entire building (including all of the units). **Synapse would like to better understand the rationale for limiting the MURB tariff to the house meter and whether the MURB tariff could be applied to the individual unit meters as well.** We expect that the bulk of the electricity consumption of MURBs is not measured by the house meter, and thus MURBs are likely to continue to face a disincentive to shift load due to the demand charge on the standard tariff.	• Revenue Neutrality – These models on the structural bill change for the Small General and General CPP tariffs assuming 18 events, are included in the Appendix section of the Technical Session 2 presentation. • MURB TOU Pilot Tariff – The MURB TOU Pilot Tariff, which falls under the General Rate class, applies to the house meter for the building. The existing demand charge on MURB buildings only applies to the load that is metered on the house meter. Any individual unit load, metered separately, would not be subject to a demand charge. The MURB rate does not impose restrictions on including some or all individual unit loads in the MURB owner's house meter at the discretion of the MURB operator. This is in line with current practices for other MURB buildings. MURB buildings feature a wide variety of metering configurations and the MURB rate is designed to accommodate general rate meters in these buildings, regardless of their metering setup. NS Power has conducted energy modeling on buildings with diverse HVAC and metering configurations, demonstrating that energy savings are achievable with appropriate investments by the MURB, with additional savings available with additional load shifting investments (shown on page 49 from the 2024 TVP Technical Session 2).[9] This approach to the MURB TOU Pilot Tariff is consistent with Commitment 9(a) within the M09777 Consensus Agreement[10] which has been completed as described and as discussed in stakeholder sessions over the course of the 2023/24 TVP Season, leading to the Company's 2024/25 TVP Application, and with the launch of a pilot MURB rate. For individual units within a MURB that are metered separately by NS Power, the domestic rate class applies. As such, the MURB rate, as part of the general rate class, would not be applicable. However, units in the domestic rate class have the flexibility to select the rate that best meets their needs, including the existing domestic time-of-use and critical peak pricing rates. This configuration of rates also allows for continued separation of rate classes with the flexibility of MURB operators to determine what, if any individual unit loads apply to the general rate class house meter with demand, and which loads if any remain on the domestic tenant meter without demand.

[9] M11822 – 2024/25 TVP Application, Appendix C, Attachment 4, page 49 of 63. July 31, 2024.
[10] Please refer to Appendix "A," page 6 of 7, filed on May 10, 2021, as part of the Company's original TVP Application (M09777).

Stakeholder	Comment	NS Power Response
		As part of the 2024 TVP Consensus Agreement, NS Power is exploring a potential new domestic TVP (time-varying pricing) rate that includes weekends. This rate could resemble the MURB rate structure but would be tailored specifically for residential customers which would include individual residential customers inside of MURB buildings that are individually metered. If implemented, this additional rate would provide individual residents of MURB buildings, who are directly metered by NS Power with more rate options.
Board Counsel Consultant, Synapse Energy Economics (Synapse, BCC)	**3. Current Metering & Systems Limitations** NS Power's presentation included a discussion of its current billing and metering system limitations, with the statement that these systems do not have the ability to allow net metering customers to enroll on time-varying rates or to implement time-varying or multi-part demand charges "without extensive programming, upgrades, manual intervention, or difficult to scale alternative solutions."[11] NS Power also noted that a "capital project to replace [the Customer Information System] is under development." **Synapse requests that NS Power provide an estimated timeframe for the Customer Information System project and whether the project would enable (a) net metering customers to take service on the TVP tariffs, and (b) whether it would enable time-varying demand charges or other modifications to demand charges.**	• The capabilities discussed are being incorporated into the Customer Information System (CIS) project requirements for the system. Implementation of these features and rates may require additional upgrades and configurations to other systems, which may not necessarily be part of the Customer Information System project itself. The Customer Information System will serve as an enabling technology, addressing the most challenging hurdles and significantly advancing efforts toward offering more complex rate design options. • Once the technical ability to enable time-varying net metering rates at scale is closer, each of the existing behavioural TVP rates on offer at that time will be reviewed to determine the impact enabling net metering may have on each rate. • The CIS Replacement project was included in the 2025 ACE Plan as a project for subsequent submittal, planned to be filed later in 2025. Details pertaining to the full timeline, scope and cost will be provided in the upcoming application.
Board Counsel Consultant, Synapse Energy Economics (Synapse, BCC)	**4. Rate Design Scorecard Rubric** Synapse appreciates that NS Power has developed a Rate Design Scorecard to facilitate evaluation of its tariffs. This is a useful tool to understand whether the tariffs are achieving their objectives by being attractive to customers, aligned with system costs, resulting in load shifting, and revenue neutral. As noted in the stakeholder session, Synapse has concerns with the definition of the "Customer Equality" metric. Currently the Customer Equality metric has an objective that the tariff result in a balance of 50/50 structural winners and losers. Synapse suggests that this objective may not add meaningful value. For example, a tariff that is more cost reflective and revenue neutral but results in 70% of customers paying lower bills is not objectively worse than a tariff that is more cost reflective and revenue	• The 50/50 structural winners and loser analysis serves two main purposes: ▪ It serves as a starting point for a new rate until participant data is available to calculate revenue neutrally. We would agree that once revenue neutrality is measurable with participants' loading data and actual load shift it can be beneficial to place less weight on the structure winner metric. This can be seen in the CPP rate where we've emphasized calibrating for revenue neutrality over 50/50 structural winners and losers in the previous changes to this rate. ▪ It is a risk mitigation tool to minimize potential revenue loss that could impact the customers who do not opt in to these rates to ensure any revenue requirement shifts are gradual and controlled over time. This allows Nova Scotia Power additional flexibility in exceeding targets when practical.

[11] NS Power, 2024/25 Areas of Focus, Technical Session 1, slide 27. Revised distribution: March 13, 2025.

Stakeholder	Comment	NS Power Response
	neutral but results in 60% of customers paying lower bills. In fact, it would be generally *better* for more customers to enjoy bill savings, as long as the "structural losers" do not experience significant rate shock. In the case of opt-in rates, it is unlikely that many structural losers will enroll in a TVP tariff, and thus this is unlikely to be a concern. **Synapse therefore recommends that this metric be removed from the scorecard.** In addition, it is not clear whether the Fair Value metric includes capacity or not. Thus, Synapse proposes that the **Fair Value metric be modified to include marginal generation, transmission, and distribution capacity costs**. That is, rather than "Tariff volumetric rates correlate to the marginal cost of electricity (i.e., largely fuel)" the objective be "Tariff volumetric rates correlate to the marginal cost of electricity (including marginal generation, transmission, and distribution costs)." To estimate hourly marginal capacity costs, these costs should be primarily allocated to the hours in which peak demand is likely to occur, or when capacity is otherwise limited (e.g., during the highest net load hours).	• For those two reasons Nova Scotia Power would recommend retaining 50/50 structural winners and loser metric in the scorecard. We do acknowledge this measure has some shortcomings and that a rate scoring low on this metric may still be desirable to improve other scorecard metrics. • Additional consideration should be given to the fact that currently the TVP rates are designed to influence customers' load shape to maximize benefits to the system and savings for the customer. Behavioral rates are not targeting a high level of correlation to the COSS model and may not necessarily be cost reflective without calibration of the rate over time based on customer usage. A rate more reflective of the COSS model would likely require fewer risk mitigation measures but may not necessarily attract the same level of load shifting or customer savings that a behavioral rate with an amplified price signal might. Nova Scotia Power would be willing to explore adding a more cost reflective rate to our TVP offering based on stakeholder interest. • Nova Scotia Power agrees that alignment of costs, although indirectly included in the scorecard, could be better reflected. Hourly marginal cost of generation and transmission, as described by Synapse, is similar to the DSM avoided cost series. This methodology is included in the TVP avoided cost calculations. In Technical Session 2 we will review a potential new metric that adds TVP avoided costs result to the scorecard more directly included breaking out capacity, T&D, and fuel components to better capture this gap highlighted by Synapse.
Board Counsel Consultant, Synapse Energy Economics (Synapse, BCC)	**5. Marketing and Recruitment** NS Power's presentation on marketing and recruitment reveals that the Company has engaged in a wide variety of marketing and recruitment strategies through various channels over the past year, and that these tactics have been largely successful. Synapse is especially encouraged by the reporting and analytics implemented by the marketing team, which has allowed the team to monitor which approaches are most effective and to modify approaches as needed. **Synapse would like to better understand the relative effectiveness and cost of the various marketing strategies, as well as the total TVP marketing and recruitment costs to date.** Specifically, Synapse would appreciate NS Power providing the following information: **1. For each communication strategy (e.g., email, postcard, digital ad, etc.) the acquisition cost per customer enrolled through that communication channel.**	1. Costs are not typically broken down by communication strategy, for instance one customer may have received more than one touchpoint, rather the grouping of those expenses and the number of customers. With this, based on our marketing spend in 2024, it cost an average of $25 recruit one new residential customer and $413 to recruit one new SMB customer. Detailed cost acquisition tracking by channel would be an incremental expense that is currently not in scope of the project. However, we are continuing to evolve how we track performance based on what's feasible and in scope for the upcoming year. As recruitment scales, it is anticipated that costs per customer acquired may reduce. 2. The total marketing and recruitment effort, including labour, for Year 4 was $150,031 for residential and $17,749 for business.

Stakeholder	Comment	NS Power Response
	2. Total cost of the marketing and recruitment efforts to date, including NS Power internal labor.	
Board Counsel Consultant, Synapse Energy Economics (Synapse, BCC)	**6. Next Steps** Synapse looks forward to participating in future stakeholder sessions. For Technical Session 2, which will focus largely on demand charges, Synapse requests that NS Power present the following data to aid in the scoping of item 3.3: 1. **For the General class, a description of the various types of transformers included in the cost of service study under the cost category "transformers." That is, what proportion of these transformers are dedicated to serving only the individual General Service customer, versus what proportion are located upstream on the distribution system.** 2. **Using NS Power's most recent cost of service study, for the General class, what proportion of costs classified as demand-related are related to the Generation function, Transmission Function, and Distribution function.** Synapse reiterates that it appreciates NS Power's willingness to meaningfully engage with stakeholders on these important topics. We look forward to continuing to participate in these discussions.	As requested, NS Power has included these two items (re. the scoping of 2024/25 Areas of Focus Work Plan item 3.3) in the Technical Session 2 deck; please refer to slides 10 and 11.

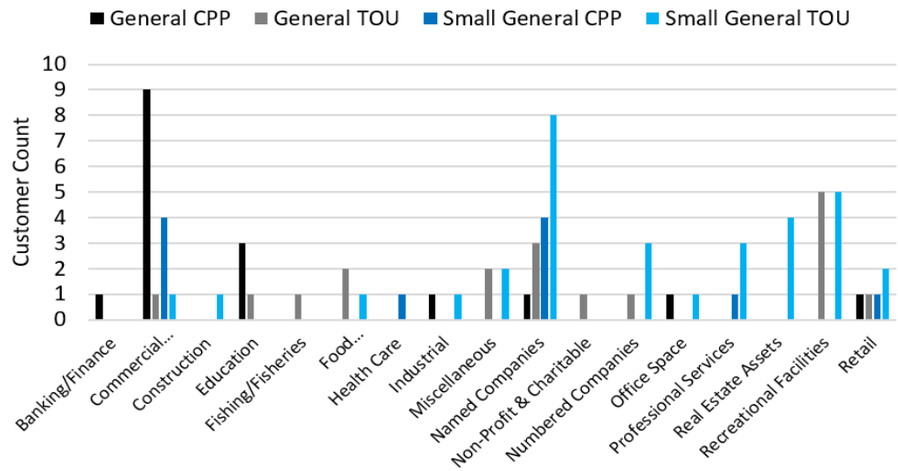
TIME-VARYING PRICING TARIFF PROGRAM
NS POWER RESPONSES TO STAKEHOLDER COMMENTS

TVP Session	Technical Session 2 – held 7 April 2025
Comments Received	17 April 2025
Responses Filed	30 June 2026

Stakeholder	Comment	NS Power Response
Small Business Advocate (SBA)	**Slide 19: Load Characteristics of Small Business Customers that may Shift Load in Response to TVP** 1. Please describe in more detail what constitutes a "meaningful load shift." a. Does a certain load shift threshold need to be met for the load shift to be considered "meaningful"? b. If so, what is the threshold? If not, what were the parameters used to determine a "meaningful" load shift?	1. Typically, any statistically significant load shift would be considered meaningful. With no statistically significant load shift occurring a visual review was conducted of all load shapes where any visually observable load shift was considered meaningful for this exercise only. This is a qualitive assessment to help identify if there are any customer segments in the pilot group who may be shifting load but are being obscured by large confidence intervals that may be a result of small sample size. a. No, for this assessment any load shift observed was considered meaningful. b. Any visual indication from load shapes that load shifting appears to have occurred in response to pricing signals could be considered meaningful for the purposes of this review Statistical significance remains the threshold overall.
	2. Were there other TVP SMB customers who, while not meeting the criteria for "meaningful load shift", nonetheless experienced a more limited degree of load shift? If so, please discuss how many customers and to what degree load shifting occurred.	2. No.
	3. Excluding the 1 customer who indicated they had not taken direct action to shift load, of the remaining 3 customers who experienced meaningful load shifting and "would not be scalable in Nova Scotia to a broader segment": (a) Please discuss whether these customers experienced overall bill savings or bill increases due to their load shifting behavior. Please describe the magnitude of the bill savings/increases. (b) During the stakeholder session, NSP commented that these customers are not scalable to the broader SMB customer segment because their customer type is unique in the province. Even if their customer type is unique to those customers, are their "Pre-Pilot" load shapes, shown on Slide 19, also unique?	3. (a) These customers were identified based on visual indications, not a result of a regression analysis, any bill analysis completed on only three customers would not yield meaningful results. Bill savings will be investigated in future EM&V reports if the data set allows. (b) Every load shape is to some degree unique. How similar load shapes may be before being considered similar would be dependent on the use case. With no indication that load shape is indicative of load shifting potential, NS Power is not able to determine a criterion to group load shapes based on their load shifting potential. (c) Currently there is no indication that load shape is indicative of load shifting potential. As a result, there is no plan to target such customers on this basis. (d) i. The chart below shows the 2024 customer segmentation model categories and the TVP tariff those customers are enrolled in.

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TIME-VARYING PRICING TARIFF PROGRAM
NS POWER RESPONSES TO STAKEHOLDER COMMENTS

Stakeholder	Comment	NS Power Response
Small Business Advocate (SBA)	(c) Two of the "Pre-Pilot" load profiles on Slide 19 appear to be relatively flat throughout the day. Please discuss if NSP has other SMB customers with load profiles that also similarly relatively flat. If so, please discuss NSP's plan to target such customers so that they can experience TVP load shifting benefits in a similar way to the two customers on Slide 19, that also have relatively flat load profiles. (d) Regarding the bullet which states "no characteristics of small business customers have been found that indicate a potential for load shifting outside of the MURB space": i. Please list and describe the types of SMB customers that were enrolled in TVP, but did not experience meaningful load shift. ii. Of these customer types, please indicate how many customers were enrolled under each customer type? iii. Are there other SMB customer types that have not been enrolled and represented in the evaluation process, yet could experience meaningful load shifting and arc scalable? If so, please describe NSP's plan to target those customer types.	 ii. The number of customers enrolled in TVP rate per category is included in the above chart. iii. NS Power has not identified any customer segment outside of the MURB space that are able and willing to shift load.
	Slide 20: Recruitment and Customer Outreach 1. Regarding the bullet, under the heading *What we are proposing,* which states: "target[ing] larger commercial customers with a profile of accounts who would achieve better value in TVP rates this could be universities, retail chains, etc.": (a) Please describe NSP's approach to achieving better value for customers with a profile of accounts. Is the intent to have those larger customers pilot TVP with one of their accounts before rolling out across all accounts? Or is the "better value" achieved by getting the larger customer to enroll the entire profile of accounts in TVP?	1. (a) Due to the high touch requirements of enrolling SMB customers, the greatest value is achieved when these customers sign up several accounts at once, even when it is a just a portion of their accounts to assess the rates. These customers typically also have existing relationships with account managers and can be offered these rates during regular conversations when beneficial to the customer. Anecdotally, these customers also appear the most engaged with some of them indicating they will attempt to shift load.
	2. Please discuss whether NSP is targeting SMB customers that have a load profile that would benefit meaningfully from enrolling in TVP (i.e., a significant portion of the bill occurs during peak hours when load shifting is most impactful).	2. This approach was explored. Customers who could save after shifting load were identified as priority recruitment targets. After further review of these priority recruitment targets, it appeared their business models would likely not respond to load shifting.

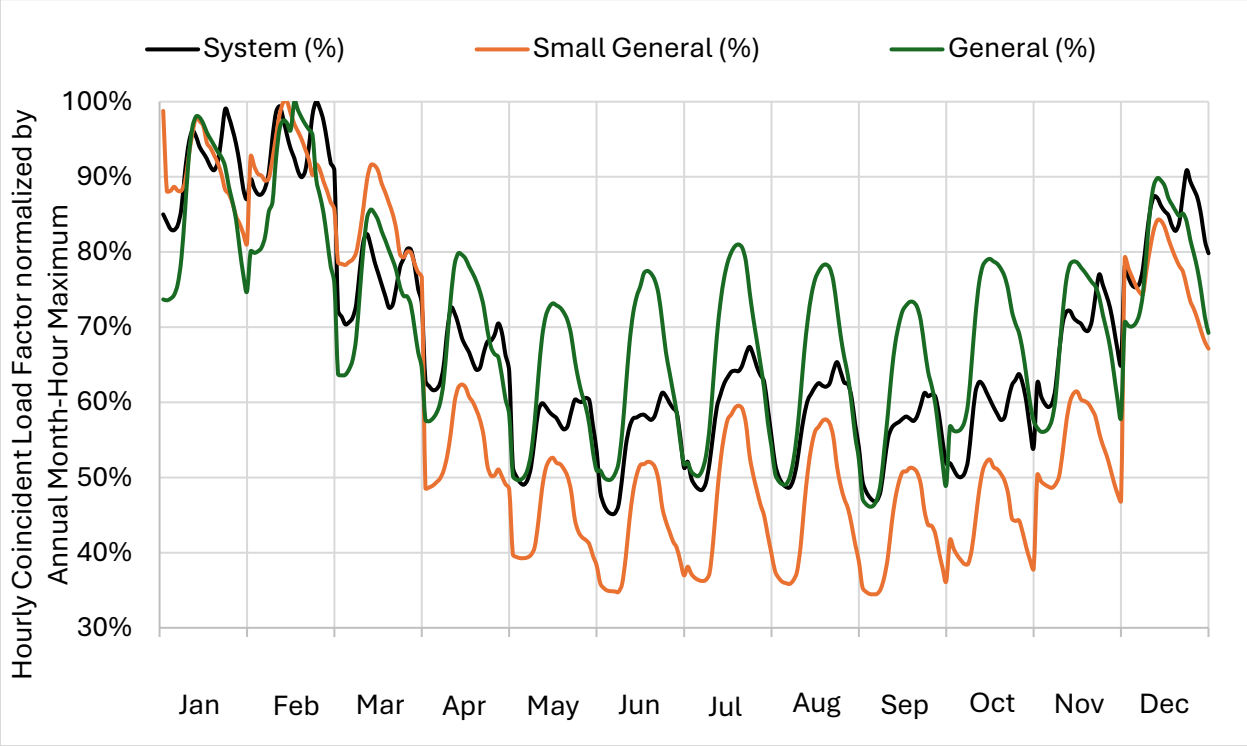
Nova Scotia POWER An Emera Company

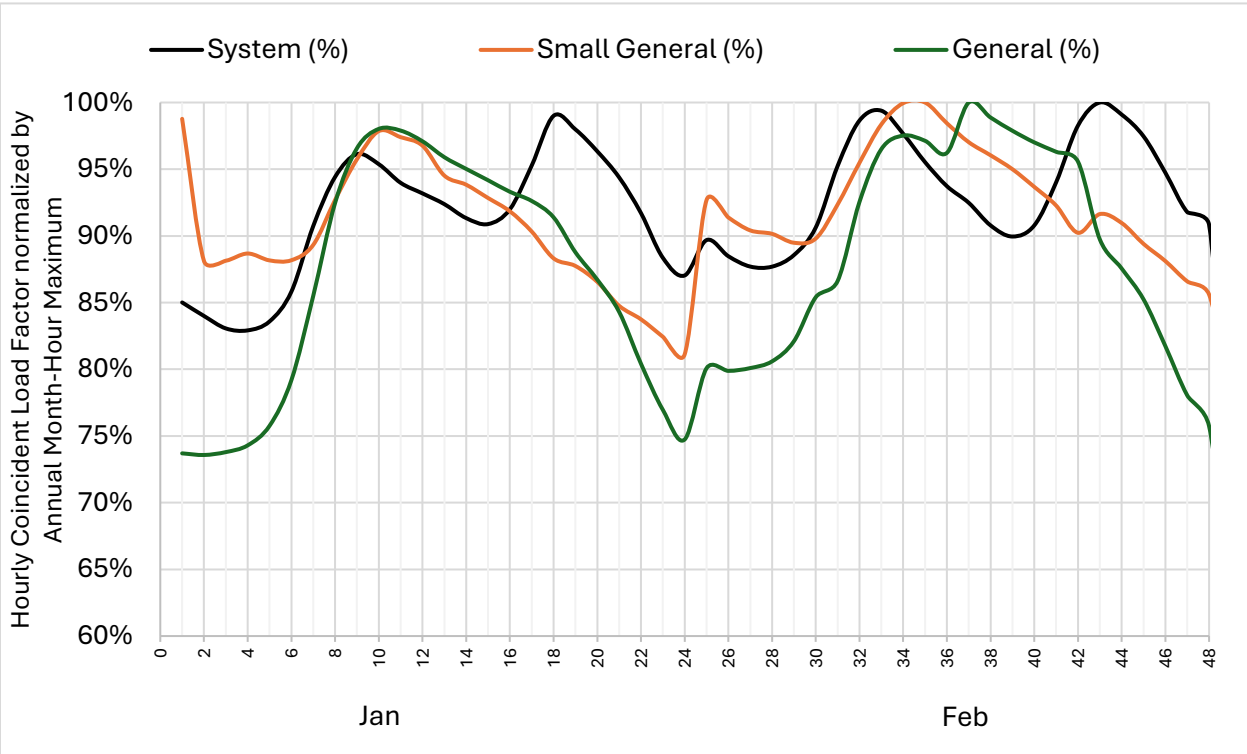
TIME-VARYING PRICING TARIFF PROGRAM
NS POWER RESPONSES TO STAKEHOLDER COMMENTS

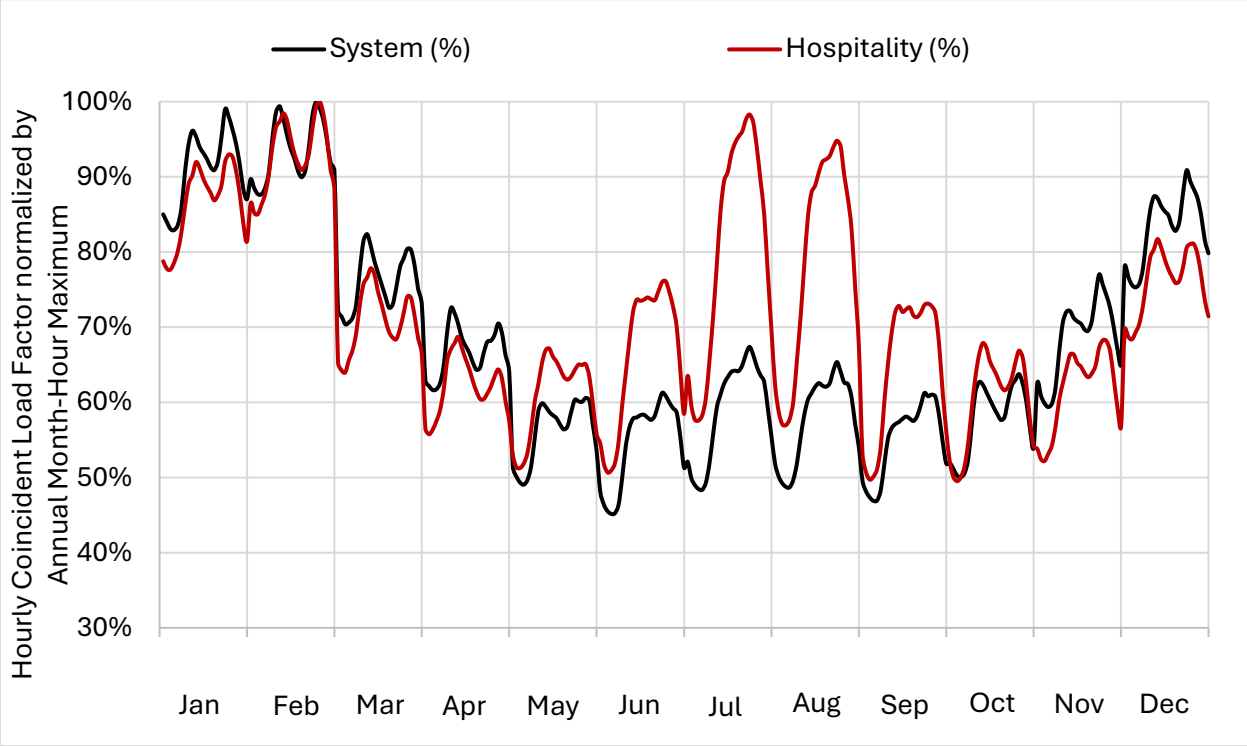
Stakeholder	Comment	NS Power Response
Small Business Advocate (SBA)	(a) If so, please discuss NSP's approach for reaching these customers. If not, please describe why NSP is not targeting such customers.	(a) For the next active recruitment period, this approach will be repeated using learnings from the most recent EM&V and incorporating feedback from key account managers such as filtering on customers with multiple accounts customers.
	3. Please discuss which associations NSP plans to target that would benefit from TVP rates. Will the associations be targeted based on results from the Customer Segmentation Model discussed on Slide 28 (i.e., targeting segments with the largest load distribution or with load profiles best suited for TVP rates)?	3. When active recruitment begins, NS Power plans to advertise with associations who have a membership that would benefit from the rates and are receptive to hearing about TVP. Which associations are targeted will be determined throughout the year as opportunities are balanced with resources.
	Slide 21: Customer Hesitations and Potential Solutions 1. Regarding the bullet stating that a potential change could be to "revise the TOU rate structure to target increased savings for customers who do shift 4%-6% of load": (a) Please describe what revisions NSP is proposing to increase savings for that customer group. (b) Does NSP anticipate that such revisions would also provide further benefits for the structural winner customers, who are hesitant to participate because they "often felt [potential savings] to be not enough to be worth the effort'?	1. (a) Currently, NS Power is not proposing improvements to the SMB TVP SMB rates in the upcoming enrolment year. (b) Any changes are expected to alter the nature of structural winners in both directions. As these are behavioural rates, the main target is increasing the value of shifting load. A rate focused on cost service alinement over behavioural load shifting would open additional targeting of structural winners but may not target behavioural load shifting as effectively.
	Slide 28: Verticals in Commercial Segmentation Model 1. In addition to NSP's offer, during Technical Session #2, to provide the number of customers and load distributions that fall into each customer segment, the SBA respectfully requests that NSP also provide the typical load profile of each customer segment to facilitate the assessment of which segments can benefit from TVP. 2. Of the 28 Commercial Segments identified through the Segmentation Model, please identify which of those segments align with NSP's proposed idea on Slide 20 to "target larger customers with a profile of accounts who would achieve better value in TVP rates."	1. Please refer to Attachment 1. 2. Potentially all segments could fall under the target of larger customers with a portfolio of accounts as they would not be industry specific.

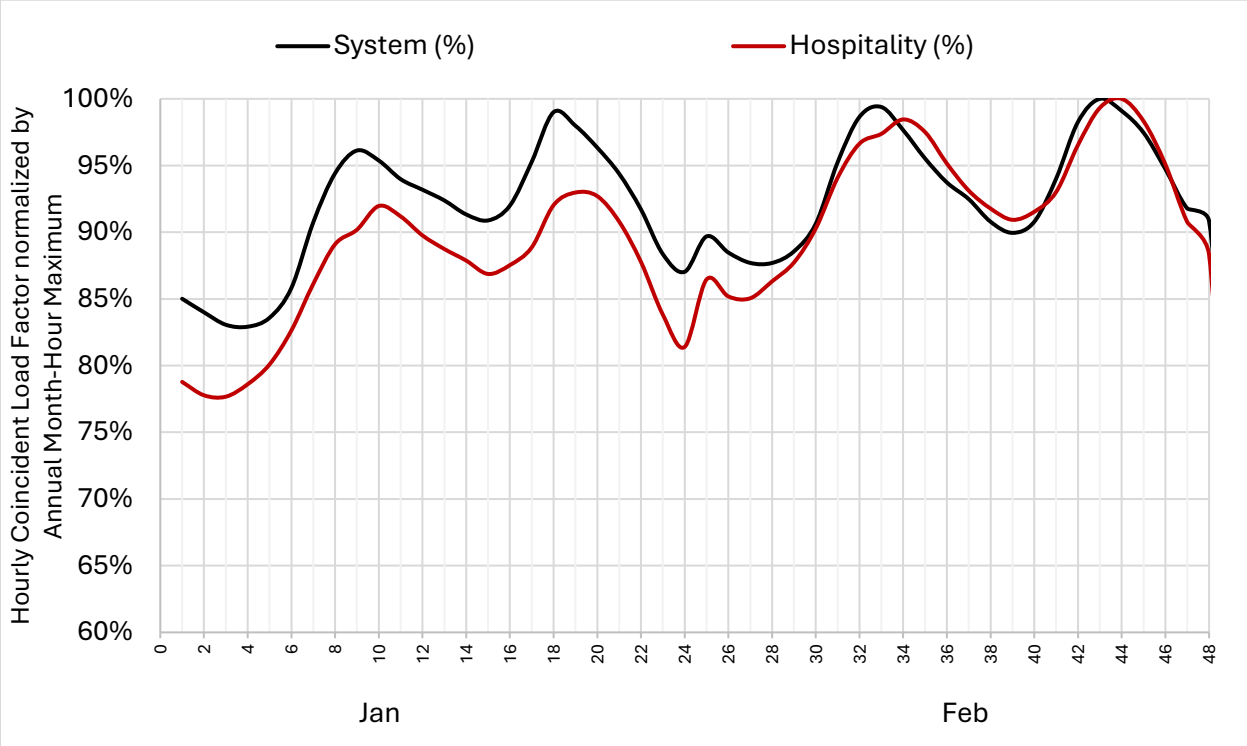
The charts below show the hourly average load profile per month of several business vertical segments normalized by their respective maximum month-hour load (kW). After each business vertical load shape chart, a zoomed in chart of January and February is provided. These zoomed-in charts are for clarity and do not contain additional data not in the preceding chart. The table below shows the average maximum hourly kW consumed per customer for scale.

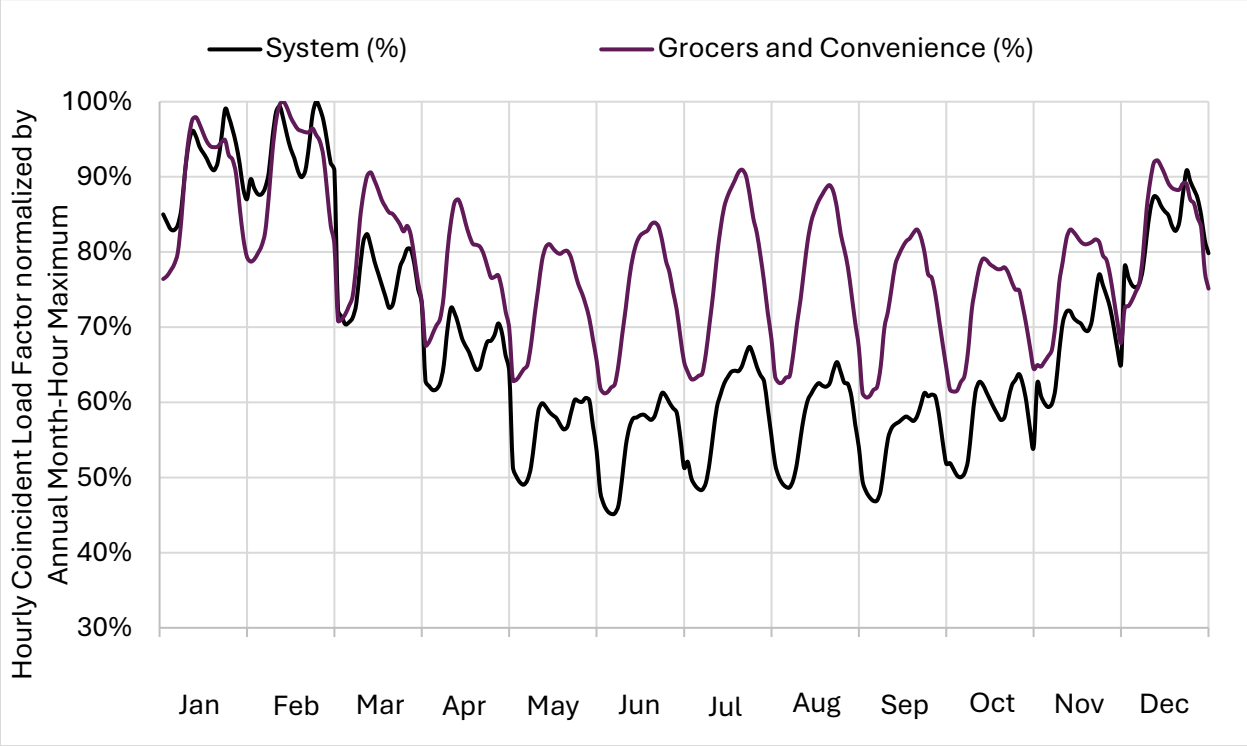
	Peak Month	**Peak Hour (Hour Start)**	**Average kW per Customer Segment on Peak Hour**
Small General	January	10:00	3.6
General	January	12:00	30.5
Forestry/Lumber	February	11:00	11.3
Commercial Sales/Services	February	09:00	8.7
Hospitality	February	19:00	9.0
Office Space	February	08:00	11.4
Food Service/Restaurants	July	13:00	17.7
Banking/Finance	February	08:00	11.4
Grocers and Convenience	February	09:00	46.1

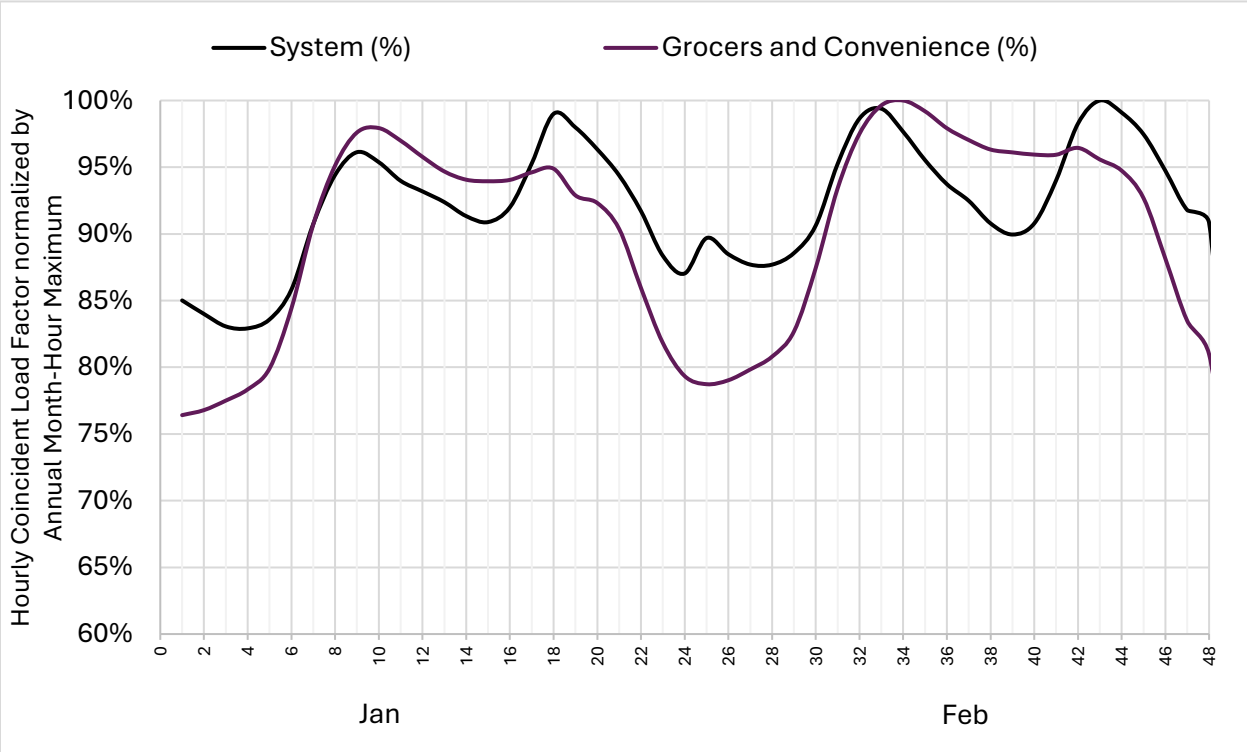

System (%)
Small General (%)
General (%)
Hourly Coincident Load Factor normalized by Annual Month-Hour Maximum
100%
90%
80%
70%
60%
50%
40%
30%
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

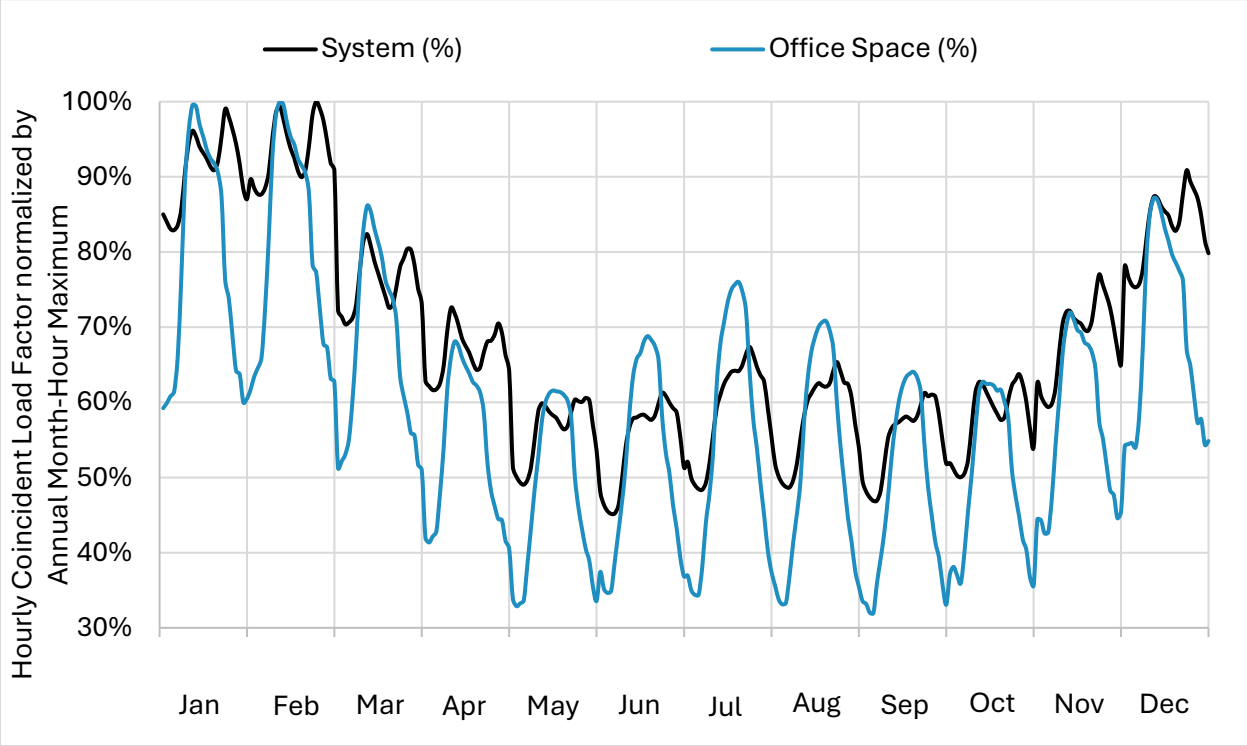

System (%)
Small General (%)
General (%)
Hourly Coincident Load Factor normalized by Annual Month-Hour Maximum
100%
95%
90%
85%
80%
75%
70%
65%
60%
0
2
4
6
8
10
12
14
16
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20
22
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28
30
32
34
36
38
40
42
44
46
48
Jan
Feb

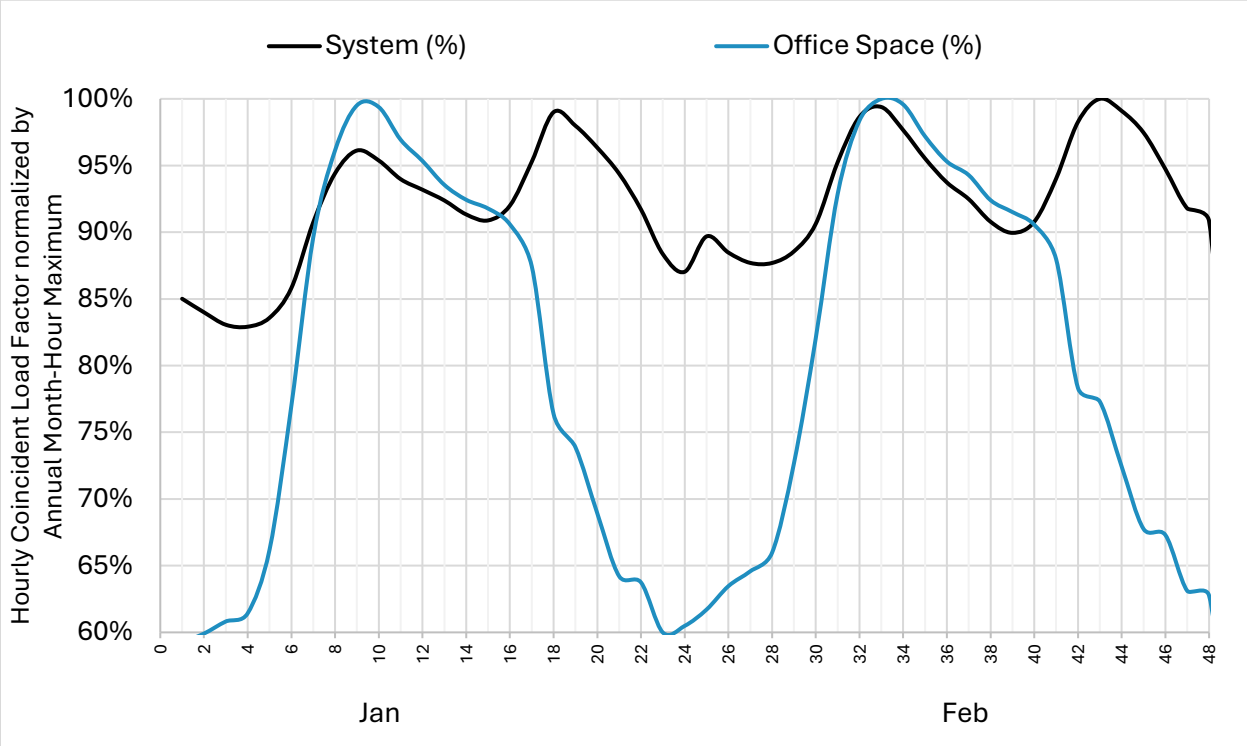

System (%)
Hospitality (%)
Hourly Coincident Load Factor normalized by Annual Month-Hour Maximum
100%
90%
80%
70%
60%
50%
40%
30%
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

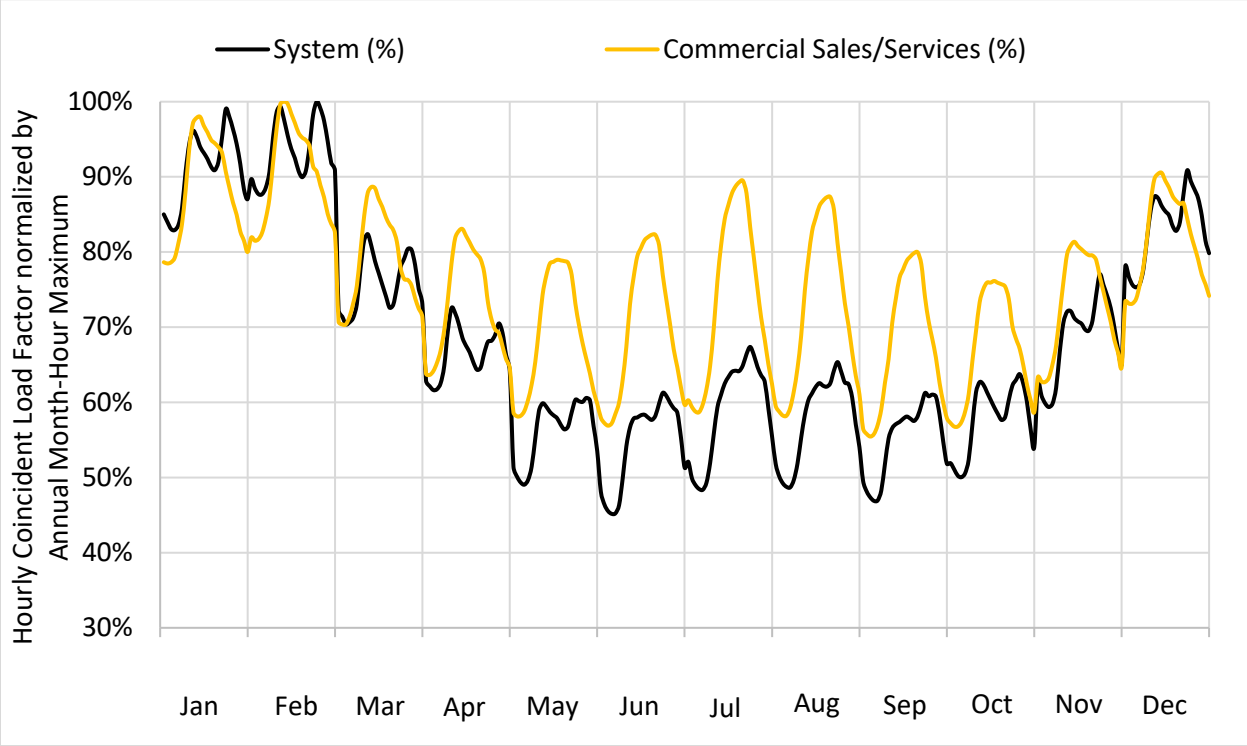

System (%)
Hospitality (%)
Hourly Coincident Load Factor normalized by Annual Month-Hour Maximum
100%
95%
90%
85%
80%
75%
70%
65%
60%
0
2
4
6
8
10
12
14
16
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20
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32
34
36
38
40
42
44
46
48
Jan
Feb

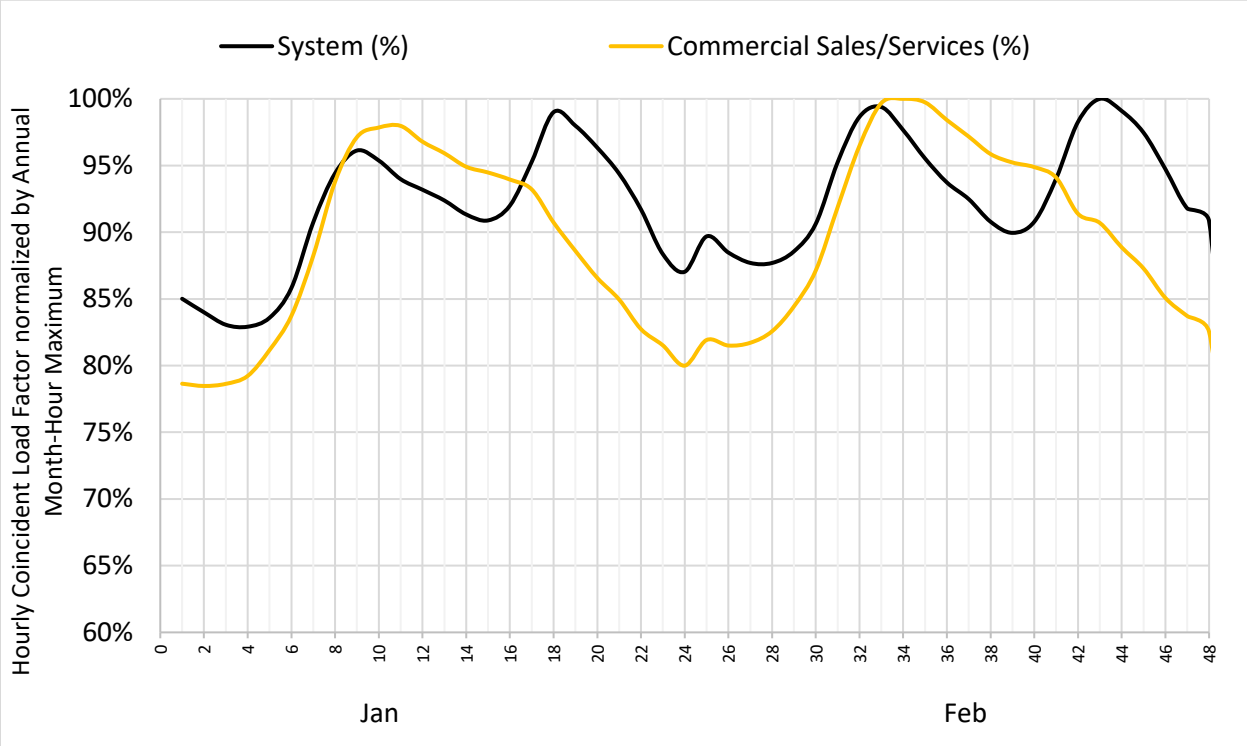

System (%)
Grocers and Convenience (%)
Hourly Coincident Load Factor normalized by Annual Month-Hour Maximum
100%
90%
80%
70%
60%
50%
40%
30%
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

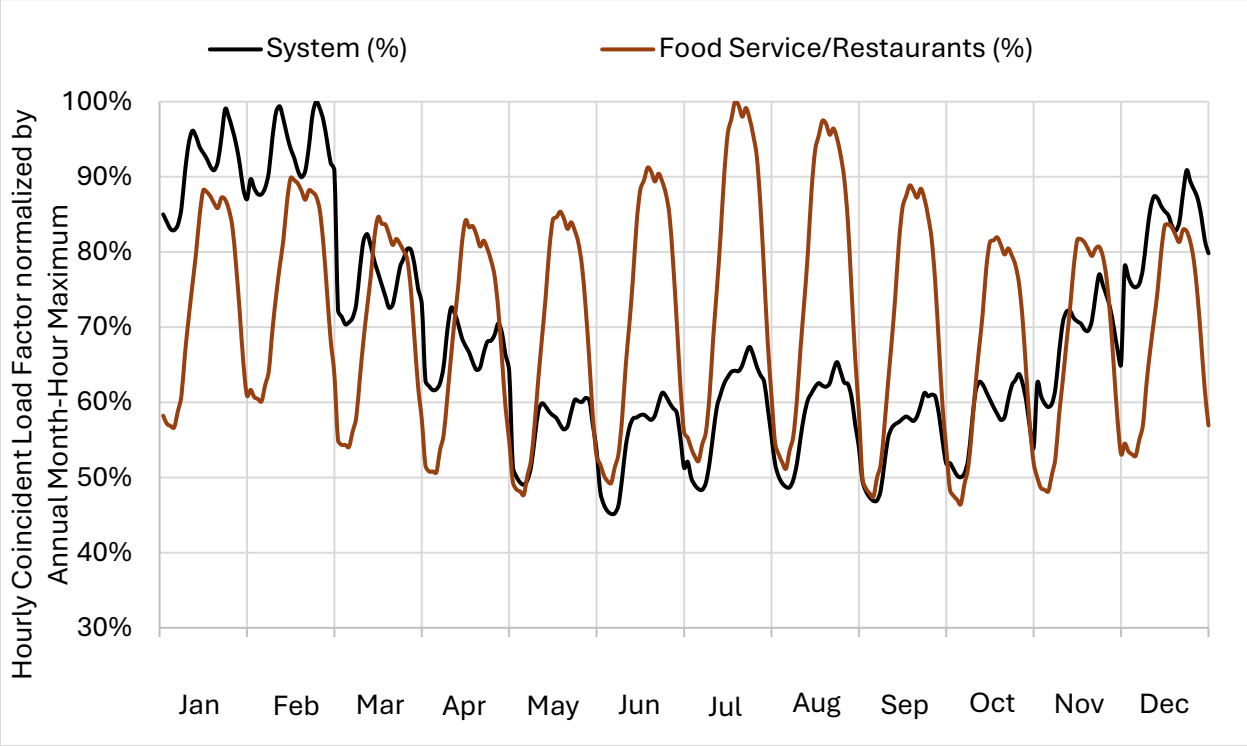

System (%)
Grocers and Convenience (%)
Hourly Coincident Load Factor normalized by Annual Month-Hour Maximum
100%
95%
90%
85%
80%
75%
70%
65%
60%
0
2
4
6
8
10
12
14
16
18
20
22
24
26
28
30
32
34
36
38
40
42
44
46
48
Jan
Feb

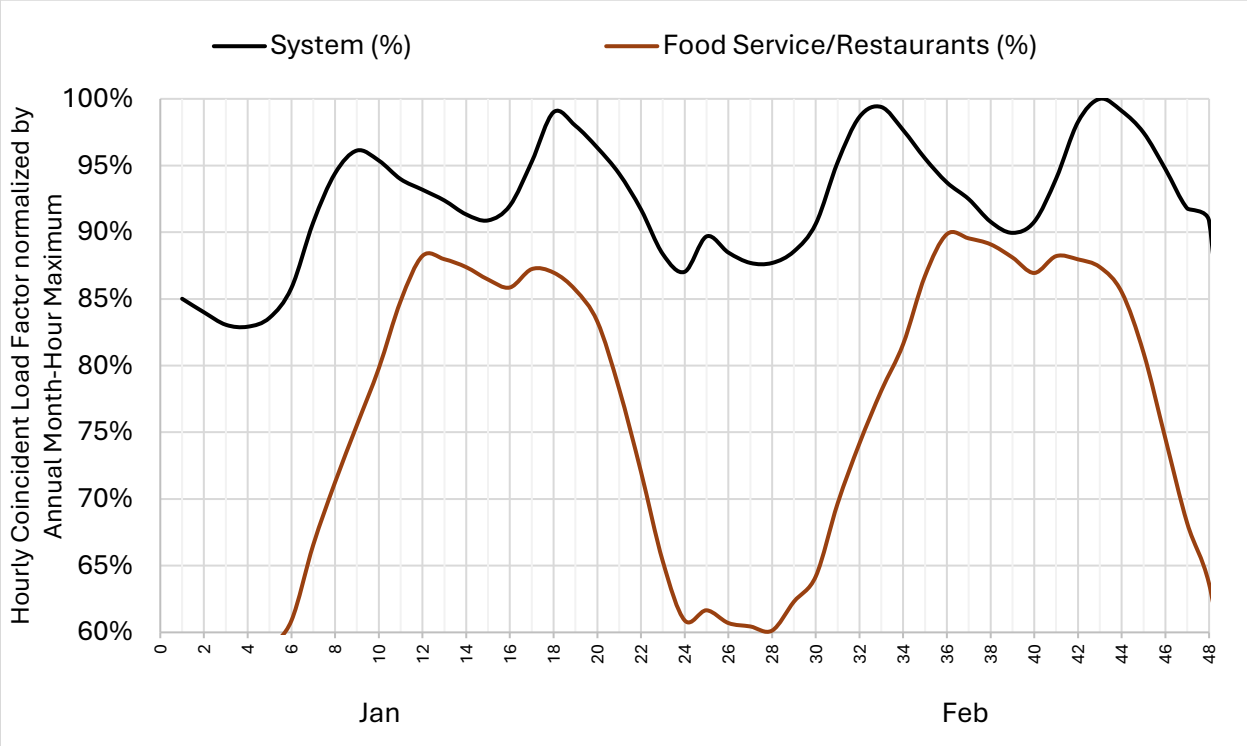

System (%)
Office Space (%)
Hourly Coincident Load Factor normalized by Annual Month-Hour Maximum
100%
90%
80%
70%
60%
50%
40%
30%
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

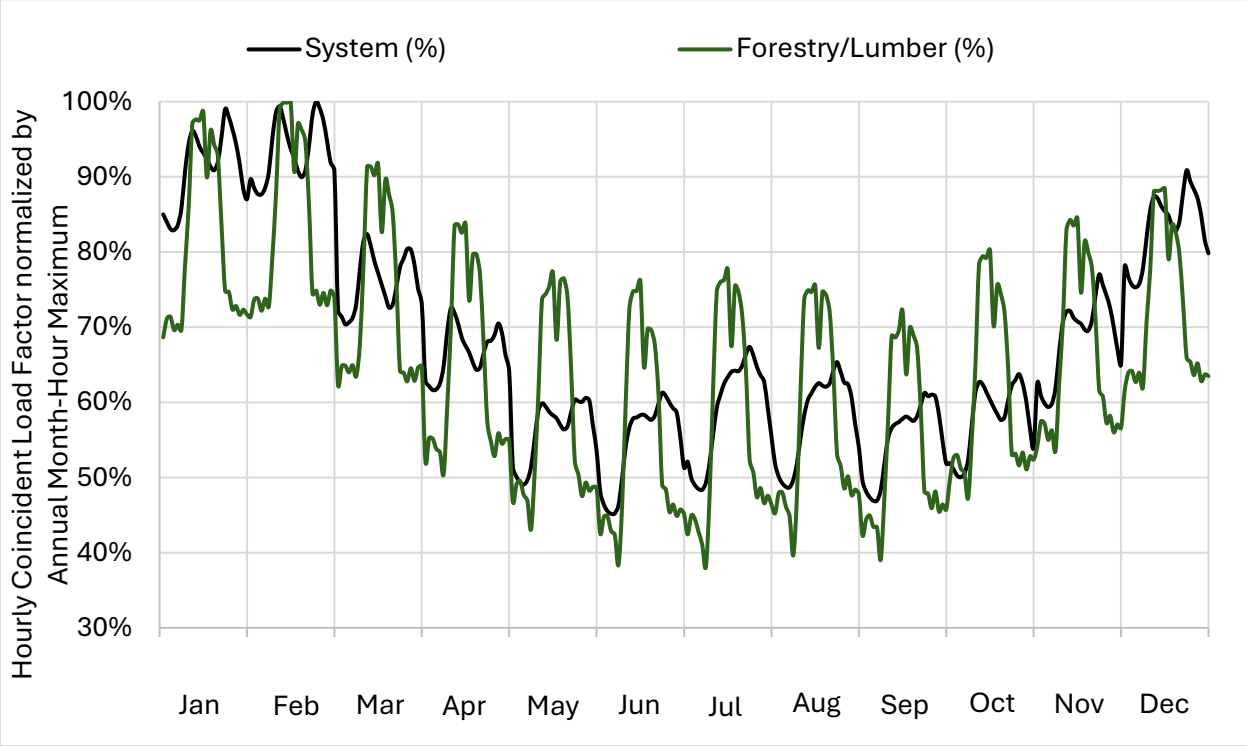

System (%)
Office Space (%)
Hourly Coincident Load Factor normalized by Annual Month-Hour Maximum
100%
95%
90%
85%
80%
75%
70%
65%
60%
0
2
4
6
8
10
12
14
16
18
20
22
24
26
28
30
32
34
36
38
40
42
44
46
48
Jan
Feb

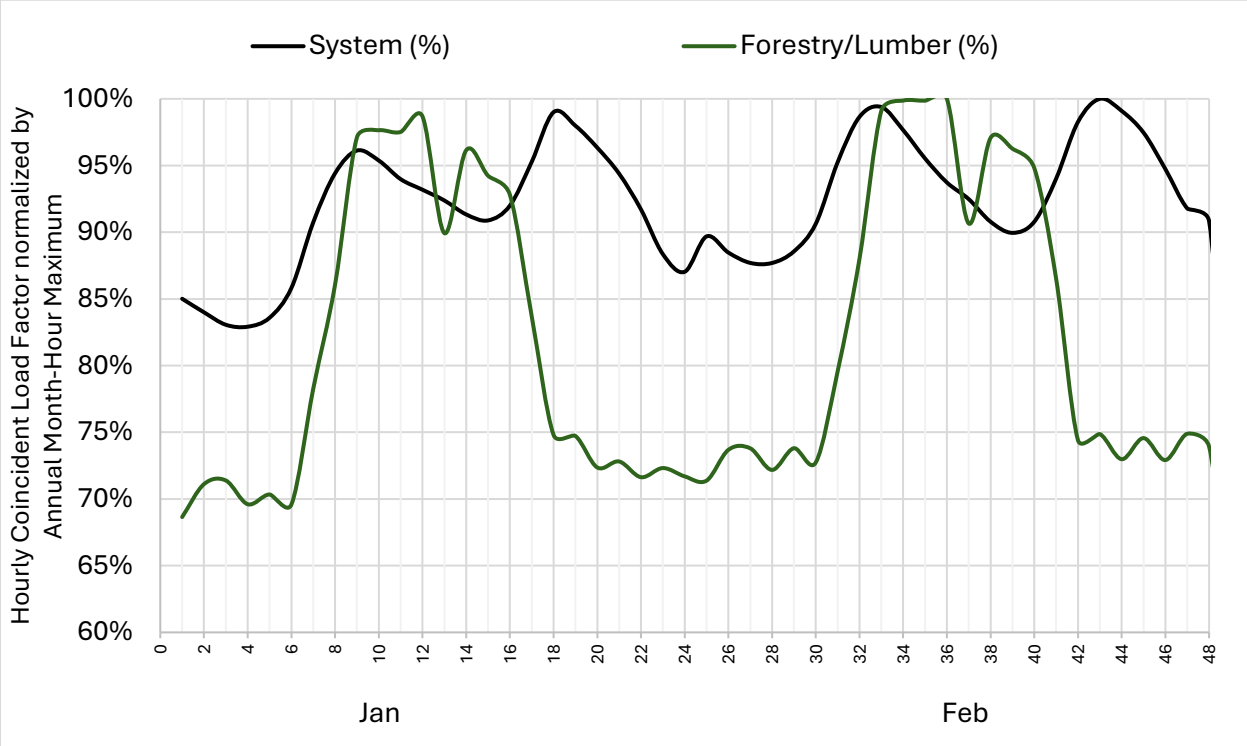

System (%)
Commercial Sales/Services (%)
Hourly Coincident Load Factor normalized by Annual Month-Hour Maximum
100%
90%
80%
70%
60%
50%
40%
30%
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

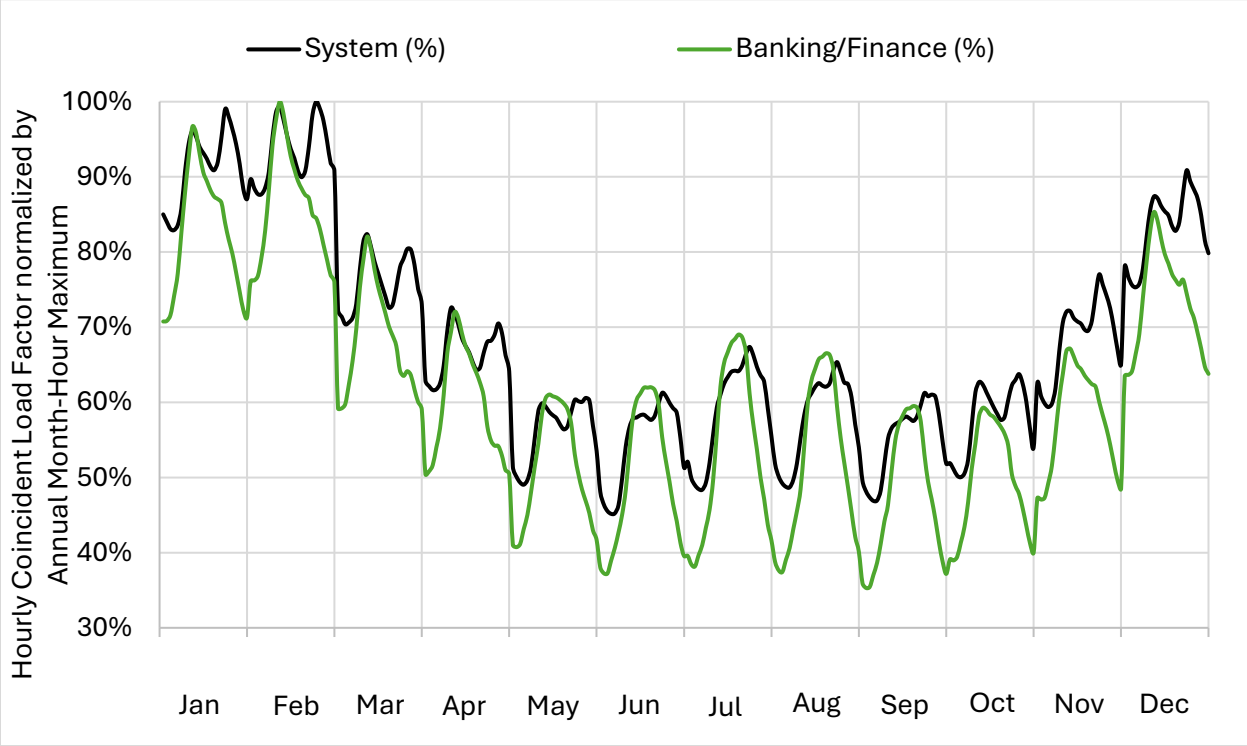

System (%)
Commercial Sales/Services (%)
Hourly Coincident Load Factor normalized by Annual Month-Hour Maximum
100%
95%
90%
85%
80%
75%
70%
65%
60%
0
2
4
6
8
10
12
14
16
18
20
22
24
26
28
30
32
34
36
38
40
42
44
46
48
Jan
Feb

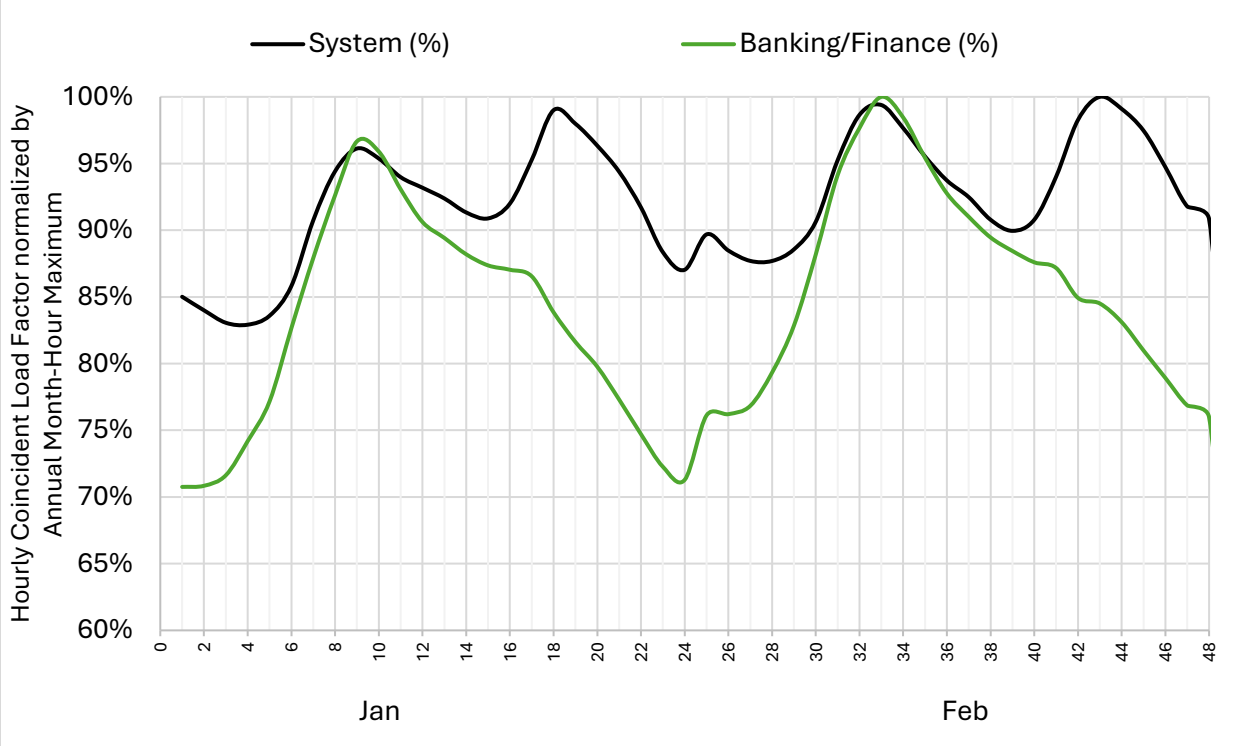

System (%)
Food Service/Restaurants (%)
Hourly Coincident Load Factor normalized by Annual Month-Hour Maximum
100%
90%
80%
70%
60%
50%
40%
30%
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec


System (%)
Food Service/Restaurants (%)
Hourly Coincident Load Factor normalized by Annual Month-Hour Maximum
100%
95%
90%
85%
80%
75%
70%
65%
60%
0
2
4
6
8
10
12
14
16
18
20
22
24
26
28
30
32
34
36
38
40
42
44
46
48
Jan
Feb


System (%)
Forestry/Lumber (%)
Hourly Coincident Load Factor normalized by Annual Month-Hour Maximum
100%
90%
80%
70%
60%
50%
40%
30%
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec


System (%)
Forestry/Lumber (%)
Hourly Coincident Load Factor normalized by Annual Month-Hour Maximum
100%
95%
90%
85%
80%
75%
70%
65%
60%
0
2
4
6
8
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12
14
16
18
20
22
24
26
28
30
32
34
36
38
40
42
44
46
48
Jan
Feb


System (%)
Banking/Finance (%)
Hourly Coincident Load Factor normalized by Annual Month-Hour Maximum
100%
90%
80%
70%
60%
50%
40%
30%
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec


System (%)
Banking/Finance (%)
Hourly Coincident Load Factor normalized by Annual Month-Hour Maximum
100%
95%
90%
85%
80%
75%
70%
65%
60%
0
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42
44
46
48
Jan
Feb